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 #15-5
December 3, 2015 8:00 a.m. – 5:00 p.m. EST
December 4, 2015 8:00 a.m. – 12:00 p.m. EST
Albany Marriott Hotel
189 Wolf Road, Albany, NY 12205-1100
Meeting Room Albany/Colonie
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, 2015
NPCC Glossary of Terms, dated January 18, 2012

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 Approval of RSC Work Plan 2016
5.3 RSC Scope 2016
5.4 Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities
5.5 Definition of Facility

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	12/3/15 Call-In
Project 2010-07.1 Vegetation Management	12/16/15 (F)	12/16/15 (I)	Sean Bodkin	1:00PM
Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes	1/8/16 (F)	1/8/16 (A)	Al McMeekin	1:45PM
Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005, BAL-006, FAC-001	1/11/16 (F)	1/11/16 (A)	Darrel Richardson	1:15PM
Project 2015-10 Single Points of Failure TPL-001	12/17/15 (I)		Katherine Street	1:30PM
Comments: (I) – Informal; (F) – Formal **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 Disturbance Monitoring Standard PRC-002-NPCC-01 status update.

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

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

9.0 NPCC Non-Standards

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

9.1 Directories:

9.1.1 Directory#8 System Restoration (status of CO11 Review and Criteria Clarification)

9.1.2 Directory#9 and #10 Capability Verification (status of CO7 review).

9.1.3 Directory#7 SPS (status pending RAS PRC -012-2)

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	February 18th - Call	March 11th - Meeting
April 15th - Call	May 20th - Call	June 10th - Meeting
July 15th - Call	August 19th - Call	September 23rd Meeting
October 21st - Call	November 18th - Call	December 9th - 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 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 NERC Alerts released since the last RSC meeting.

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC)

January 14th – Call	February 18th – Call	March 17-18th Meeting
April 15th – Call	May 13th – Call	May 19-21st Workshop
June 16-17th Meeting	July 15th – Call	August 19th – Call
September 22-23rd Meeting	October 14th – Call	November 10-12th Workshop
December 3-4th Meeting		

14.2 NPCC Board of Directors Meeting (BOD) 2015

February 3rd-4th Meeting	March 25th – Call	April 29th Meeting
June 4th – Call	June 25th Meeting	August 5th - Call
September 8th-9th Meeting	October 28th – Call	December 2nd Meeting

14.3 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

14.4 2016-2017 NERC Standards Committee Team Elections

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2015 Meeting Dates

February 18th-19th, 2015 NextEra Energy Offices, Juno Beach FL
April 22th & 23th, 2015 Dominion Offices, Richmond VA
June 23rd & 24th, Saratoga NY
October 7th & 8th, Montreal Quebec
December 3rd & 4th, Albany NY

15.2 Tentative RSC 2016 Meeting Dates

February 17th-18th, NextEra Energy Offices, Juno Beach FL
April 13th & 14th, NPCC Offices, New York NY
June 22nd & 23rd, Saratoga NY
August 10th & 11th, Toronto Canada
October 5th & 6th, Boston MA
December 8th & 9th, Montreal Canada

15.3 RSC 2015 Conference Call Schedule (calls can be scheduled 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 16	January 30	February 13
March 6	March 20	April 2
May 1	May 15	May 29
June 12	July 10	July 23
August 14	August 28	September 11
September 25	October 23	November 6
November 20	December 18	

15.4 Tentative 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.

NPCC, Inc.

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 #15-4
October 7, 2015 10:00 a.m. – 5:00 p.m. EST
October 8, 2015 8:00 a.m. – 3:00 p.m. EST
Hydro-Quebec TransEnergie Complexe Desjardins
150 Rue Ste-Catherine O
Meeting Room Fiabilite 19th Floor, East Tower (Corner of Rene-Levesque/Jeanne-Mance)
Montreal Quebec, Canada H2X 3Y2
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, 2015
NPCC Glossary of Terms, dated January 18, 2012

Attendees:

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Kal Ayoub	FERC	Guest	1 & 2	
2.	Howard Gugel	NERC	Guest	1 & 2	
3.	Guy Zito	Northeast Power Coordinating Council		1 & 2	
4.	Lee Pedowicz	Northeast Power Coordinating Council		1 & 2	
5.	Gerry Dunbar	Northeast Power Coordinating Council		1 & 2	
6.	Ruida Shu	Northeast Power Coordinating Council		1 & 2	
7	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1 & 2	
8.	Jim Grant	New York Independent System Operator	2	1 & 2	
9.	Rob Vance	New Brunswick Power Corporation	1 & 2	1 & 2	
10.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1 & 2	
11.	Dermot Smyth	Consolidated Edison Co. of New York, Inc.	3	1 & 2	Via Phone
12.	Randi Heise	Dominion Resources Services	Guest	1 & 2	Via Phone
13.	Salvatore	New York Power Authority	5	1	Via Phone

	Spagnolo				
14.	Kathleen Goodman	ISO-NE	2	1	
15.	Si Truc Phan	Hydro-Québec TransÉnergie	2	1 & 2	
16.	Chantal Mazza	Hydro-Québec TransÉnergie	2	1 & 2	
17.	Sylvain Clermont	Hydro-Québec TransÉnergie	1	1	
18.	Brian Robinson	Utility Services	5	1 & 2	Via Phone
19.	Brian Shanahan	National Grid	1	1 & 2	
20.	Michael Jones	National Grid	3	1 & 2	
21.	Payam Farahbakhsh	Hydro One Networks	1	1 & 2	
22.	Helen Lainis	Independent Electricity System Operator	2	1 & 2	
23.	Ron Falsetti	AESI	Guest	1 & 2	
24.	Don Weaver	New Brunswick Energy and Utilities Board	Guest	1 & 2	
25.	Don Nelson	Massachusetts Department of Public Utilities	Guest	1 & 2	Via Phone
26.	Michele Tondalo	The United Illuminating Company	Guest	1 & 2	Via Phone
27.	Al McMeekin	NERC	Guest	1	Via Phone
28.	Mark Olson	NERC	Guest	1	Via Phone
29.	Darrel Richardson	NERC	Guest	1	Via Phone
30.	Sean Bodkin	NERC	Guest	1	Via Phone
31.	Scott Barfield-McGinnis	NERC	Guest	1	Via Phone
32.	Barbara Nutter	NERC	Guest	1	Via Phone

Introductions and Chair's Remarks

Guy Zito Called the meeting to order at 10:00AM on Wednesday October 7, 2015.
Guy Zito discussed Cost Risk Reduction Analysis with the committee and ongoing activities for this efforts.
The Cost Effective Analysis Process is being revised to Cost Risk Reduction Analysis which includes quantifying costs, costs associated with risk reduction, monetary and societal costs if you don't mitigate the risk.

The goal is to integrate the cost-risk analysis process into the standards development process.
The process will be posted for comments and is likely to be piloted to see if it produces value. Guy Zito indicated that he was working on the process with Fred Plett, an NPCC Board of Director member who was leading the effort

NPCC Antitrust Compliance Guidelines

The NPCC Antitrust Compliance Guidelines were read by Lee Pedowicz.

Agenda Items:

1.0 Review of Agenda

Guy Zito coordinated the inclusion of two additional presentations (TPL-007-1-GMD and Remedial Action Schemes-RAS) by HQ personnel.

2.0 RSC Meeting Minutes

Approval of Minutes—there were no revisions to the Final Meeting Minutes 6-23-15.
Herb Schrayshuen made a motion for approval.
Helen Lainis seconded the motion.
The Meeting Minutes were approved (all in favor) as documented.

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 Teams spreadsheet.

3.2 Executive Tracking Summary
Ruida Shu provided updates on Executive Tracking Summary which is posted on the NPCC Website.

3.3 NERC Project Tracking Spreadsheet
Guy Zito provided a brief updated on the NERC Project Tracking Spreadsheet.
Herb Schrayshuen mentioned that FERC has issued an extension on TPL-007-1 comments to October 22nd, 2015.

4.0 Open Action Items

4.1 Open Action Items List
Guy Zito requested to remove Items 4.3-4.5 on the list.
Guy Zito added an item to determine tentative RSC meeting dates and locations for 2016.
Lee Pedowicz will coordinate June 2016 meeting at Saratoga Springs with CC to ensure no overlap.

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
Guy Zito mentioned this was an item for information only.

5.2 NOPR on Revised Critical Infrastructure Protection Reliability Standards
Guy Zito discussed the NOPR on CIP with members of RSC.
The commission proposes to approve seven critical infrastructure protection (CIP) Reliability Standards. Outstanding issues that will likely result in a Directive include

"supply chain". A presentation was given which was developed by TFIST Chairman. The RSC was not in full agreement with the interpretation of the term "supply chain". (See 5.6 below)

5.3 Clean Power Plan

Guy Zito provided a brief update on the Clean Power Plan.

EPA determined that greenhouse gas pollution threatens American's health and welfare by leading to long-lasting changes in our climate that can have a range of negative effects on human health and environment. CO2 is the most critical and it is about three-quarters of global greenhouse gas emissions and 82 percent of US greenhouse gas emissions.

Herb Schrayshuen made the following comments on the CPP:

NERC has formed a CPP Advisory Committee under the Planning Committee to vet assumptions and help guide NERC staff's work towards a CPP Phase 2 study which will focus on the reliability impact of the final CPP rule. NERC currently plans for the CPP Phase 2 study to be released in March 2016. NERC is also planning to produce an interim guidance report outlining considerations for state environmental agencies to consider on the various issues related to reliability as they develop their state compliance plans. The guidance document is presently being planned for a January 2016 release date.

5.4 Draft Outline of CEA Comments on FERC NOPR TPL-007

Draft Outline of CEA Comments on FERC NOPR TPL-007 was presented to the members of RSC and CEA comments on FERC NOPR TPL-007 were filed as read. Louis Gibson (as role of TP) and Sebastien Guillon (SME) presented Hydro-Quebec assessment on TPL-007-1.

5.5 Project 2015-07 Internal Communications Capabilities

This topic is covered by NERC Standard Developer Sean Bodkin. RSC members questioned the use and meaning of the term "capability" and expressed concern that this means 100% ability all the time. Numerous concerns were raised that cell phones may go through "dead zones" and that capability could mean having something but not using it, such as having a radio system but not utilizing it. Comments will be sent in to reflect this and SDT members are working on answering NPCC's concerns.

5.6 FERC Proposal for Cyber Supply Chain Requirements and NIST SP800-161

Guy Zito provided a presentation on FERC Proposal for Cyber Supply Chain Requirements and NIST SP800-161.

There are three major concerns by the industry.

1. Should NERC develop a Cyber Supply Chain standard?
2. What are the anticipated requirements to include in the Cyber Supply Chain standard?
3. What is a reasonable time frame to develop a standard?

Howard Gugel provided a brief discussion on NERC's response to the FERC Proposal.

"NERC has requested the Commission to provide two years for standard development to allow sufficient time for NERC to consider these issues and engage in educational and outreach efforts, such as holding technical conferences and establish a task force, to provide a better understanding of the nature of supply chain

risks and the extent to and manner in which a mandatory Reliability Standard can effectively protect against those risks." This is the response by NERC to the Commission.

5.7 FERC--Availability of Certain North American Electric Reliability Corporation Databases to the Commission

On September 17th, 2015 the commission asked to have access to TADs, GADs, and Misoperations data. Canadian entities provide, data on a voluntary basis for TADs and GADs are the data is not complete. The data is not mandatory for Canada and FERC specified in the NOPR that they would not require any access to international data.

Helen Lainis from IESO questioned if the commission will take the "US" only data and propose standards based on the "US" data only where they are an international organization.

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	10/7/15 Call-In
Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	10/5/15 (F)	10/5/15 (I)	Al McMeekin	1:00PM
Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves		10/8/15 (F)	Darrel Richardson	NA
Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	11/9/15 (F)	11/9/15 (I)	Mark Olson	1:30PM
Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls	11/12/15 (F)	11/12/15 (I)	Darrel Richardson	1:45PM
Project 2015-07 Internal Communications Capabilities COM-001-3	11/16/15 (F)	11/16/15 (I)	Sean Bodkin	2:00PM
Project 2007-06.2 Phase 2 of System Protection Coordination	11/19/15 (F)	(A)	Scott Barfield-McGinnis	2:15PM
New Standards Balloting and Commenting System			Barbara Nutter	2:30PM
Comments: (I) – Informal; (F) – Formal **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

Project 2010-05.3:

Al McMeekin called in at 1:00PM to provide an update on Project 2010-05.3.
Ballot period just ended on Monday October 5th, 2015
Next SDT team is on the week of October 26th, 2015 at Montreal, Canada.
Al McMeekin's goal is to get the standard post it around middle of November so the standard can be brought to the board on February 2016.

Project 2010-14.1:

General consensus from the RSC is that it is not wise to shed load to maintain reserve.
Members of RSC have submitted comments on this Project but it seems the SDT did not make any changes to comply with the comments.

Project 2010-05.3:

Mark Olson called in at 1:30PM to provide an update on Project 2009-02.
The SDT discussed various TOP and IRO standards to ensure there is no overlapping to both standards.
The SDT also reviewed members of NPCC's comments on the necessity for the standard.

Project 2010-14.2.2:

Darrel Richardson called in at 1:44PM to provide an update on Project 2010-14.2.2.
The SDT tried to determine if this standard is necessary. A survey has been conducted and majority industry response were that this standard is not necessary.
The standard is posted for comment until November 12th, 2015.
The focus should be on the whitepaper.

Project 2015-07:

Sean Bodkin called in at 1:53PM to provide an update on Project 2015-07.
Due to the differences in risk factors the SDT decided to split up the requirement into two so Distribution Provider and Transmission Operator will be separated.
Distribution Provider risk factor is medium.
Transmission Operator risk factor is high.
A question is raised by a RSC Member regarding the necessities for this standard since there is already a COM standard for communication.
NERC responses were that the original standard focused on the external communication between entities to entities. The new standard is trying to address the internal communication within entity.
Two issues raised by a NPCC Member:

1. Communication between field personnel using radio or cell phones are not always reliable due to dead spots in the area.
   NERC staff responded that the standard is only trying to capture the internal communication based on their capabilities.
2. Geographically separated control centers is the second issue since there is no specific distance determined for the separated control centers.
   NERC staff responded that any separation is valid and will provide additional more explanation in the posting documents.

Project 2007-06.2:

Scott Barfield McGinnis called in at 2:13PM to discuss Project 2007-06.2.
Project 2007-06.2 is posted on October 6th, 2015 for comment and ballot.
The SDT received most of the comments from GOPs.
The SDT used real time operations time horizon for GOPs and added RAS into the standard so there are no gaps.
The SDT did not include RC into TOP-009-1 due to the recent work of IRO group of standards.
A suggestion is made on R3 to use the word "control" instead of "affect" in the standard for GOP.

New Standards Balloting and Commenting System:

Barbara Nutter called in at 2:29PM to provide an update on the changes to the new SBS system.
Additional reference sources are provided in the system.
Archive link is a useful way for you to find your voting history.
NERC will be implementing a "One Stop Shop" location for all the useful links.
A new enhancement is the ability to edit through survey until comment period ends.
Another new enhancement is the ability to be able to bring up the most current survey for voters.
The Goal is to have these enhancements to complete these by the end of the year.

Sylvain Clermont provided a brief update on the activities of MRC.

6.2 Ballot History (Since last RSC Meeting)

Ruida Shu reviewed the Ballot History and pointed out that all the technical justification provided by Guy Zito in his Ballot Recommendation are now also posted on the NPCC website.

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 Disturbance Monitoring Standard PRC-002-NPCC-01 status update. Drafting Team recommends that PRC-002-NPCC-01 be retired; a new directory developed requiring RSC approval.

Lee Pedowicz provided a brief update on the status of the SDT on Disturbance Monitoring.
Lee Pedowicz presented the recommendation by the SDT to the RSC on Disturbance Monitoring which is to retire PRC-002-NPCC-01 and develop a new Directory.
Brian Robinson made the motion for approval.
Jim Grant seconded the motion.
The decision to develop a new Directory for Disturbance Monitoring is approved (all in favor).

8.1.2 Automatic Underfrequency Load Shedding PRC-006-NPCC-1 status. RSC to consider approval of additional Drafting Team members.

Si-Truc Phan made the motion for approval.

Rob Vance seconded the motion.
Automatic Underfrequency Load Shedding PRC-006-NPCC-1 standard drafting team was approved (all in favor) as read.
Herb Schrayshuen made the motion to amend the SDT.
Payam Farahbakhsh seconded the motion.
The Automatic Underfrequency Load Shedding PRC-006-NPCC-1 standard drafting team was amended (all in favor) as read. (Added Dean Latulipe from National Grid to the Roster)

8.1.3 Hydro-Quebec Variance for PRC-006-2 Automatic Underfrequency Load Shedding status.
Action Item: Guy Zito will get in touch with Barbara Nutter to get a word version of the PRC-006-NPCC-1 standard.

8.2 Activities on Hold: Regional Standard BAL-002-NPCC-01: Regional Reserve Sharing
Guy Zito has requested this topic to be removed from Agenda going forward.

9.0 NPCC Non-Standards

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

9.1 Directories:

9.1.1 Directory #1 Design and Operation of the Bulk Power System and Directory #4 System Protection Criteria---Criteria approved via ballot of the Full Member Committed ---9/30/2015.
Gerry Dunbar thanked the Members for their respective organizations participation.

9.1.2 Directory#8 System Restoration (status of CO11 Review and Criteria Clarification) Mr. Dunbar reported that the TFCO Restoration Working Group (CO11) has been reviewing D#8:

- Reviewing battery testing criteria for redundancy with PRC -005-2.(CO11 anticipates returning revised Directory#8 to the TFCO in the 4th Qtr. of 2015 in order for TFCO to post recommended changes).
- TFCO and CO11 also reviewing Criteria Clarification request from OPG. (CO11 Clarification was posted to the Open Process and CO11 has recommended responses to comments received in the Open Process to the TFCO. Anticipate presenting completed clarification to the RCC for approval in December).

9.1.3 Directory#9 and #10 Capability Verification (status of CO7 review).Mr. Dunbar provided an update on D#9 and D#10: TFCO Working Group CO7 currently reviewing the criteria in D#9 and D#10 with MOD-25-2 which becomes enforceable on 7-1-2016. MOD-25-2 has a staged implementation over 5 years and will not be fully enforceable until 2019. CO7 Working Group will provide a recommendation to the TFCO in early 2016, which will be posted, approved by the RCC and ultimately balloted by the Full Member committee.

9.1.4 Directory#7 SPS (status pending RAS PRC -012-2)

Mr. Dunbar reported that NPCC is monitoring the development of PRC - 012-2 along with the pending regulatory approval of the NERC BOT approved revised definition of RAS prior to recommending any changes to the criteria within D#7.

9.2 Directory Information item:

9.2.1 Revision to Existing Language in each NPCC Directory for the listing of ERO Standards: Mr. Dunbar reported that subsequent to the recent RSC decision to retain the list of ERO standards within each Directory, NPCC will revise the introduction to the section of each Directory containing the ERO standards (see below) and also transfer the subject list within each Directory to an Appendix.

(Existing)

"The NERC ERO Reliability Standards containing requirements that are associated with this Directory include but may not be limited to:"

(Revised)

"The NERC ERO Reliability Standards containing requirements associated with this Directory, but not necessarily enforceable in all NPCC areas, include but may not be limited to:"

Also the list of ERO standards in each Directory will be moved into a separate Appendix within each document.

10.0 RSC Member Items of Interest

10.1 RSC Roster

Action Item: Remove Diane Barney from the RSC roster and get the updated title for Greg Campoli from Jim Grant.

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	February 18th - Call	March 11th - Meeting
April 15th - Call	May 20th - Call	June 10th - Meeting
July 15th - Call	August 19th - Call	September 23rd Meeting
October 21st - Call	November 18th - Call	December 9th - 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 Four new Lessons Learned have been issued since the last RSC meeting.

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

13.3 Revisions to the NERC Standard Processes Manual – Section 6
Guy Zito provided an update on the revisions to the NERC Standard Processes Manual – Section 6.
Main focus will be changing the field testing portion of the Standard Processes Manual.

13.4 Hydro-Quebec assessment on TPL-007-1
Louis Gibson (as role of TP) and Sebastien Guillon (SME) presented Hydro-Quebec assessment on TPL-007-1.
KP9 solar storm went by HQ on October 7th, 2015. Si-Truc Phan presented their data and graphs on the GMD storm.

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC)

January 14th – Call	February 18th – Call	March 17-18th Meeting
April 15th – Call	May 13th – Call	May 19-21st Workshop
June 16-17th Meeting	July 15th – Call	August 19th – Call
September 22-23rd Meeting	October 14th – Call	November 10-12th Workshop
December 3-4th Meeting		

14.2 NPCC Board of Directors Meeting (BOD) 2015

February 3rd-4th Meeting	March 25th – Call	April 29th Meeting
June 4th – Call	June 25th Meeting	August 5th - Call
September 8th-9th Meeting	October 28th – Call	December 2nd Meeting

14.3 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

14.4 2016-2017 NERC Standards Committee Team Elections

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2015 Meeting Dates

February 18th-19th, 2015 NextEra Energy Offices, Juno Beach FL
April 22th & 23th, 2015 Dominion Offices, Richmond VA
June 23rd & 24th, Saratoga NY
October 7th & 8th, Montreal Quebec
December 3rd & 4th, Albany NY

February 17-18, 2016 RSC Meeting in NextEra.

15.2 RSC 2015 Conference Call Schedule (calls can be scheduled as needed)

all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 29086775)

January 16	January 30	February 13
March 6	March 20	April 2
May 1	May 15	May 29
June 12	July 10	July 23
August 14	August 28	September 11
September 25	October 23	November 6
November 20	December 18	

15.3 2016 Conference Call and Meeting schedules.
The schedule is to be developed.

The meeting adjourned at 11:07AM Thursday October 8th, 2015.

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
2010-04	Demand Data (MOD C)	Standard	Andrey Oks	NPCC	212-840-1070	aoks@npcc.org
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	Michael Potishnak	Representing NPCC	413-323-8834	mpot@charter.net
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard	Michael Potishnak	Representing NPCC	413-323-8834	mpot@charter.net
2010-14.2.2	Periodic Review of BAL Standards - BAL-004	Standard	Michael Potishnak	Representing NPCC	413-323-8834	mpot@charter.net
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
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.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		jill.loewer@utilitysvcs.com
2015-06	Interconnection Reliability Operations and Coordination - IRO-006	Standard				
2015-07	Internal Communications Capabilities - COM-001	Standard				
2015-08	Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008	Standard				
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 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				
2010-04	Demand Data (MOD C)	Standard	Andrey Oks	NPCC	212-840-1070	aoks@npcc.org
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	Michael Potishnak	Representing NPCC	413-323-8834	mpot@charter.net
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard	Michael Potishnak	Representing NPCC	413-323-8834	mpot@charter.net
2010-14.2.2	Periodic Review of BAL Standards - BAL-004	Standard	Michael Potishnak	Representing NPCC	413-323-8834	mpot@charter.net
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	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						

Revised: #REF!

Tab Name	Last Revised	Summary of Changes
NERC RS Exec Tracking Summary	11/30/2015	
NERC RSAWs	11/30/2015	
NPCC RRS Tracking Summary	#REF!	- Regional Standard Processes Manual; Following NPCC BOD approval, 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
NPCC Doc Tracking Summary	#REF!	- C-00 (Discontinued) - C-05 (Retired) - C-07 (Retired) - C-21 (Retired) - C-44 (Retired)
NPCC Directory Tracking Summary	#REF!	- Directory #1, Design and Operation of the Bulk Power System posted in Open Process - Directory Development and Revision Manual - Comment Response Document posted
NPCC Directory Interpretations	#REF!	- Directory #3 Interpretation on behalf of Hydro One Networks included
Quarterly Filing to NSUARB	#REF!	Annotated worksheet to indicate that "Revisions to D#7 and D#12 approved by the Full Members on 7/9/2013. "

Prior Revision

Tab Name	Last Revised	Summary of Changes

NERC Reliability Standards Executive Tracking Summary

Revised: 11/30/2015

Line No.	Project No. / Title	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status	Active/Inactive
6	Project 2007-06.2 Phase 2 of System Protection Coordination	TOP-009-1	Yes 1st (Thru 9/11/15)	Yes (Formal Thru 11/19/15)	Yes (Additional Thru 11/19/15)						Under Development	Active
13	Project 2007-17.4 - PRC-005 FERC Order No. 803 Directive	PRC-005-3	Yes (Thru 9/16/15)	Yes (Formal Thru 9/16/15)	Yes (Initial Thru 9/16/15)							Active
15	Project 2008-02.2 — Phase 2 of Undervoltage Load Shedding	PRC-004-5, PRC-010-2	Yes (Thru 10/9/13)	Yes (Formal Thru 4/7/15)	Yes (Final Thru 4/27/15)						Under Development	Active
18	Project 2009-02 — Real-time Reliability Monitoring and Analy	"New"	Yes (Thru 8/17/15)	Yes (Formal Thru 11/9/15)	Yes (Initial Thru 11/9/15)					Concept White Paper posted for informal comment period	Under Development	Active
19	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2b, EOP-002-3, EOP-003-1, EOP-004-2 (P81, RBS), EOP-005-2 (P81, RBS), EOP-006-2 (RBS), EOP-008-1 (RBS), EOP-009-1, IRO-001-5	Yes (Thru 12/5/13)	NA	EOP-011-1 Yes (Final Thru 11/6/14)					Project initiated as a 5-year review to clarify scope, avoid potential concurrent revisions to EOP standards (Cold weather SAR)	Under Development	Active
25	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	MOD-031-2	Yes (Informal Thru 5/19/15)	Yes (Formal Thru 9/18/15)	Yes (Final Thru 10/15/15)							Active
29	Project 2010-04 Demand Data (MOD C)	MOD-031-1 (MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, MOD-021)	x	Yes (Thru 4/10/14)	Yes (Final Thru 5/5/14)		Yes (5/7/2014)			A draft RSAW has been posted to the project page.	Under Development	Active
30	Project 2010-05.3 – Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	PRC-012-2	Yes (Informal Thru 4/30/15)	Yes (Formal Thru 1/8/16)	Yes (Additional Thru 1/8/16)							Active
33	Project 2010-07.1 Vegetation Management	FAC-003-3	Yes (Informal Thru 8/24/15)	Yes (Formal Thru 12/16/15)	Yes (Initial Thru 12/16/15)							Active
37	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	For Comment (Thru 9/19/10)	Yes (Formal Thru 12/24/14)	Yes (Final Thru 12/1614)							Active
38	Project 2010-14.1 — Phase 1 of Balancing Authority Reliability-based Control: Reserves	BAL-002	NA	Yes (Thru 8/20/15) Yes (BAL-002-2)	Yes (Additional Thru 8/20/15)	Yes (BAL-001-2 on 7/25/13)	BAL-001-2 Yes (8/15/13)	BAL-001-2 Yes (4/2/14)		As of July 28, 2010 this project has merges Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control into a single project	BAL-001-2: Pending Regulatory Approval BAL-002-2: Under Development	Active
39	Project 2010-14.1 — Phase 1 of Balancing Authority Reliability-based Control: Reserves	BAL-002-2	NA	Yes (Formal Thru 3/16/14)	Yes (Additional Thru 3/16/15)					As of July 28, 2010 this project has merges Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control into a single project		Active
40	Project 2010-14.2.1 Phase 2 - Balancing Authority Reliability-based Controls	BAL-005, BAL-006 and FAC-001	Yes (Formal Thru 9/14/15)	Yes (Formal Thru 1/11/16)	Yes (Additional Thru 1/11/16)					A 30-day informal comment period for BAL standards (SAR) is now open through 8/14/14.	Under Development	Active
41	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	BAL-004-0	Yes (Formal Thru 4/15/15)	Yes (Formal Thru 11/12/15)	Yes (Initial Thru 11/12/15)							Active
59	Project 2013-03 Geomagnetic Disturbance Mitigation, Stage 2	TPL-007-1	NA	Yes (Formal Thru 11/21/14)	Yes (Final Thru 12/1614)							Active
61	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	PRC-001-1x1(X), PRC-019-2 and PRC-024-1(X)	Yes (Thru 12/19/13	Yes (Formal Thru 1/22/15)	Yes (Final Thru 3/11/15)							Active
65	Project 2015-02 Emergency Operations Periodic Review			Yes (Formal Thru 5/11/15)								Active
66	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3, FAC-011-3 and FAC-014-2		Yes (Formal Thru 6/17/15)								Active
67	Project 2015-04 Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure)		Yes (Formal Thru 4/13/15)	Yes (Formal Thru 7/27/15)	Yes (Final Thru 9/14/15)							Active
68	Project 2015-06 Interconnection Reliability Operations and Coordination - IRO-006-East and IRO-009		Yes (Informal Thru 4/15/15)	Yes (Formal Thru 7/9/15)	Yes (Final Thru 7/31/15)							Active
69	Project 2015-07 Internal Communications Capabilities	COM-001-2	Yes (Informal Thru 7/15/15)	Yes (Formal Thru 11/16/15)	Yes (Initial Thru 11/16/15)							Active
70	Project 2015-08 Emergency Operations	EOP-004-2, EOP-005-2, EOP-006-2 and EOP-008-1	Yes (Informal Thru 8/19/15)	Yes (Informal Thru 8/19/15)								Active

Acronyms;
SAR- Standards Authorization Request
RS- Reliability Standard
DT- Drafting Team
SC- NERC Standards Committee
TBD- To Be Determined
BOT- NERC Board of Trustee

NERC Reliability Standard Audit Worksheet (RSAW) Executive Tracking Summary

Revised: **11/30/2015**

ding the individual documents may be found at:
http://www.nerc.com/pa/comp/Pages/Reliability-Standard-Audit-Worksheets-(RSAWs).aspx

RSAW#	Title	Posted for Comment?	RSAW Issued?	Comments
BAL-001-1	Real Power Balancing Control Performance	x	3/28/2014	New RSAW Posted
BAL-002-02	Contingency Reserve for Recovery from Balancing Contingency Event	Yes (Thru 8/20/15)	7/22/2015	Draft RSAW Posted
BAL-003-1	Frequency Response and Bias Settings - redline of prior version	x	1/21/2015	Draft RSAW Posted
BAL-005-0.2b	Automatic Generation Control	x	5/20/2013	Revised RSAWs Posted
BAL-005-1	Balancing Authority Control	Yes (Thru 9/14/15)	8/14/2015	Draft RSAW Posted
CIP-001-2a	Sabotage Reporting	x	10/13/2012	
CIP-002-5.1	Cyber Security - BES Cyber System Categorization	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-003-6	Cyber Security - Security Management Controls	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-004-6	Cyber Security - Personnel & Training	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-005-5	Cyber Security - Electronic Security Perimeter(s)	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-006-6	Cyber Security - Physical Security of BES Cyber Systems	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-007-6	Cyber Security - System Security Management	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-008-5	Cyber Security - Incident Reporting and Response Planning	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-009-6	Cyber Security - Security Management Controls	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-010-2	Cyber Security - Configuration Change Management and Vulnerability Assessments	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-011-2	Cyber Security - Information Protection	Yes (Thru 4/14/15)	3/13/2015	Draft RSAW Posted
CIP-014-2	Physical Security	Yes (Thru 4/9/15)	2/20/2015	Draft RSAW Posted
COM-001-3	Communications	Yes (Thru 11/16/15)	10/8/2015	Draft RSAW Posted
COM-002-2a	Communication and Coordination	x	11/14/2012	
COM-002-4	Operating Personnel Communications Protocols	Yes (Thru 1/31/14)		
COM-003-1	Operating Personnel Communications Protocols	Yes (Thru 4/5/13)		
EOP-001-2.1b	Emergency Operations Planning	x	8/9/2013	Revised RSAWs Posted
EOP-002-3.1	Capacity and Energy Emergencies	x	3/20/2014	Revised RSAWs Posted
EOP-003-2	Load Shedding Plans	x	10/13/2012	
EOP-004-2	Event Reporting	N/A	10/15/2013	New RSAW
EOP-005-2	System Restoration from Blackstart Resources	x	7/17/2013	Revised RSAWs Posted
EOP-006-2	System Restoration Coordination	x	7/17/2013	Revised RSAWs Posted
EOP-008-1	Loss of Control Center Functionality	x	6/28/2013	Revised RSAWs Posted
EOP-011-1	Emergency Operations	Yes (Thru 9/25/14)	1-/20/2014	Draft RSAW Posted
FAC-001-3	Facility Interconnection Requirements	Yes (Thru 9/14/15)	8/14/2015	Draft RSAW Posted
FAC-002-2	Facility Interconnection Studies	Yes (Thru 6/25/2014)		The draft RSAW is posted for feeback through June 25, 2014.
FAC-003-3	Transmission Vegetation Management	N/A	4/24/2014	Revision serves to clarify guidance for Requirement R6 regarding initial inspections for calendar year 2014 by expanding the Note to Auditor section
FAC-003-4	Transmission Vegetation Management	Yes (Thru 12/16/15)	11/13/2015	Draft RSAW Posted
FAC-008-3	Facility Ratings	x	3/20/2014	Revised RSAWs Posted
FAC-013-2	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon	x	10/13/2012	
IRO-001-4	Reliability Coordination- Responsibilities	Yes (Thru 11/10/2014)	10/16/2014	Revised RSAWs Posted
IRO-002-2	Reliability Coordination - Facilities	x	3/20/2014	
IRO-002-4	Reliability Coordination - Monitoring and Analysis	Yes (Thru 11/10/2014)	10/16/2014	Revised RSAWs Posted
IRO-003-2	Reliability Coordination - Wide-Area View	x	3/20/2014	
IRO-005-3.1a	Reliability Coordination - Current-Day Operations	x	5/20/2013	Revised RSAWs Posted
IRO-008-2	Reliability Coordinator Operational Analyses and Real-time Assessments	Yes (Thru 12/22/2014)	11/5/2014	Revised RSAWs Posted
IRO-009-2	Reliability Coordinator Actions to Operate Within IROLs	Yes (Thru 7/8/2015)	3/16/2015	Draft RSAW Posted
IRO-010-2	Reliability Coordinator Data Specification and Collection	Yes (Thru 11/10/2014)	10/16/2014	Revised RSAWs Posted
IRO-014-1	Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	x	10/13/2012	

RSAW#	Title	Posted for Comment?	RSAW Issued?	Comments
IRO-014-3	Coordination Among Reliability Coordinators	Yes (Thru 11/10/2014)	10/16/2014	Revised RSAWs Posted
IRO-017-1	Outage Coordination	Yes (Thru 11/10/2014)	10/16/2014	Revised RSAWs Posted
IRO-018-1	Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities	Yes (Thru 11/9/15)	10/7/2015	Draft RSAW Posted
MOD-028-2	Area Interchange Methodology	N/A	10/10/2013	New RSAW
MOD-031-2	Demand and Energy Data	Yes (Thru 9/18/15)	8/14/2015	Revised RSAWs Posted
NUC-001-2		N/A	4/24/2014	Revised RSAW represent the initial release for the errata versions of the Reliability Standard
PER-001-0.2	Operating Personnel Responsibility and Authority	x	5/20/2013	Revised RSAWs Posted
PER-003-1	Operating Personnel Credentials	x	1/23/2013	
PER-005-1	System Personnel Training	N/A	10/15/2013	Revised RSAWs Posted
PRC-001-3	System Protection Coordination	Yes (Thru 5/15/15)	4/16/2015	Draft RSAW Posted
PRC-002-NPCC-01	Disturbance Monitoring	Yes (Thru 10/21/2014)	9/19/2014	Revised RSAWs Posted
PRC-004-2.1a	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	x	3/28/2014	Revised RSAWs Posted
PRC-004-3	Protection System Misoperation Identification and Correction	Yes (Thru 3/19/14)		Draft RSAW posted along with Draft Standard
PRC-004-5	Protection System Misoperation Identification and Correction	Yes (Thru 4/7/15)	2/20/2015	Draft RSAW Posted
PRC-005-1.1b	Transmission and Generation Protection System Maintenance and Testing	x	3/28/2014	Revised RSAWs Posted
PRC-005-2	Protection System Maintenance - Edits from Comments Received	x	10/14/2014	Draft RSAW Posted
PRC-005-6	Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance	Yes (Thru 9/16/15)	8/13/2015	Draft RSAW Posted
PRC-006-2	Automatic Underfrequency Load Shedding	Yes (Thru 10/8/14)	9/10/2014	Revised RSAWs Posted
PRC-010-1	Undervoltage Load Shedding	Yes (Thru 8/7/2014)		
PRC-010-2	Undervoltage Load Shedding	Yes (Thru 4/7/15)	2/20/2015	Draft RSAW Posted
PRC-012-2	Remedial Action Schemes	Yes (Thru 10/5/15)	9/3/2015	Draft RSAW Posted
PRC-023-2	Transmission Relay Loadability	N/A	10/10/2013	Revised RSAWs Posted
PRC-025-1	Generator Relay Loadability	Yes (Thru 3/11/13)		
PRC-026-1	Relay Peformance During Stable Power Swings	Yes (Thru 12/2/2014)	11/12/2014	Draft RSAW Posted
PRC-027-1	Coordination of Protection System Performance During Faults	Yes (Thru 9/11/15)	8/12/2015	Draft RSAW Posted
TOP-001-1a	Reliability Responsibilities and Authorities	x	5/20/2013	Revised RSAWs Posted
TOP-001-3	Transmission Operations	Yes (Thru 1/7/2015)	12/3/2014	Revised RSAWs Posted
TOP-002-2.1b	Normal Operations Planning	x	3/20/2014	Revised RSAWs Posted

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: 4/10/2015

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		
2	Criteria	A-10	Classification of BPS Elements	Dec-09		
3	Criteria	A-15	Disturbance Monitoring Equipment Criteria	Aug-07		
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		
7	Guideline	B-26	Guide for Application of Disturbance Recording Equipement	Sep-06		
8	Guideline	B-27	Regional Critical Asset Identification Methodology	Feb-08		
9	Guideline	B-28	Guide for Generator Sequence of Events Monitoring	Feb-12		
10	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures	May-13		
11	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems	Jan-07		
12	Procedure	C-25	Procedure to Collect Power System Event Data	Sep-07		
13	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings	Mar-07		
14	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations	Dec-09		
15	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems	Apr-06		
16	Procedure	C-39	Procedure to Collect Major Disturbance Event Data	Dec-09		
17	Procedure	C-43	NPCC Operational Review for the Integration of New facilities	Aug-08		
18	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	Nov-14		

NPCC Directory Executive Tracking Summary

Revised: 9/4/2015 Further details regarding the individual documents may be found at:

Line No.	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	Dec-09		Directory#1 and ISO NE Implementation Plan to upgrade relay protection systems on certain facilities pending RCC approval.	x
2	Directory #2	Criteria A-3	Emergency Operations	TFCO	Jun-09			
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 nthe enforcement date of PRC -005-2.	
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	TFSP	Dec-09	TFSP reviewing D#4 in accordance with NRAP review.	Directory#4 revised by TFSP pending RCC approval.	
5	Directory #5	Criteria A-6	Reserve	TFCO	Oct-12	TFCO TO coordinate possible revision of D#5 Appendix #2 to support compliance with BAL-002 revision.		
6	Directory #6		Regional Reserve Sharing		Apr-12			
7	Directory #7	Criteria A-11	Special Protection Systems	TFSP	Jul-13		Pending industry approval of PRC -012-2 and FERC approval of revised definition of RAS, NPCC Task Foreces to consider review of NPCC documents to ensure consistency with ERO Standard.	
8	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-10		TFCO Working Group CO11 reviewing Directory#8 to consider whether any of the battery testing in PRC -005-2 is dupicative with the battery testing in D8 for the Basic Minimum Power System.	
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		TFCO Working Group reviewing D#9 and D#10 to consider whether criteria will remain consistent with MOD -25-2 (MOD-25-2 is enforceable on 7/1/2016).	
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.	
11	Directory #12		Under frequency Load Shedding Program Requirements	TFSS	Jul-13			
12	Directory Manual		Directory Development and Revision Manual	N/A	Dec-13		On October 6th, 2014 the RSC approved revisions to the Directory Manual which incorporated cost considerations into the development of new or revised criteria as mandated by the NPCC BOD.	x

NPCC Directory Criteria Clarifications

Revised: **9/4/2015** 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 Interpretation	System Restoration	Pending	TFCO	Pending	Pending	Interpretation on behalf of OPG.	CO11 has rendered the interpretation which was posted to the Open Process to receive comments. CO11 addressed comment received and has returned their recommended response to the TFCO.

x

Quarterly Application to the Nova Scotia Utility and Review Board (NSUARB) for Approval of NPCC Regional Reliability Criteria

Revised: **6/17/2015**

Line No.	Filing Period	Filing Due	Filing Submitted	Comments
1	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.
2	January 1 to March 31, 2013	6/1/2013	N/A	No changes were made during the refeenced period which required filing.
3	April 1 to June 30, 2013	9/1/2013	N/A	No changes were made during the referenced period which required filing.
4	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.
5	October 1 to December 31, 2013	3/1/2014	N/A	No changes were made during the referenced period which required filing.
6	January 1 to March 31, 2014	6/1/2014	N/A	No changes were made during the referenced period which required filing.
7	April 1 to June 30, 2014	9/1/2014	N/A	No changes were made during the referenced period which required filing.
8	July 1 to September 30, 2014	12/1/2014	N/A	No changes were made during the referenced period which required filing.
9	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.
10		3/1/2015	N/A	(2) 10/6/14 the RSC approved revisions to the Directory Manual which incorporated cost considerations into the Manual.
11	January 1st to March 31st 2015	6/1/2015	N/A	No changes were made during the referenced period which required filing.
12	April 1st to June 30th 2015	9/1/2015	N/A	No changes were made during the referenced period which required filing.

Milestone Keys:

Project Tracking Spreadsheet: 2015 Project Work Plan

(Status Updated: 9/21/2015)

SP- SAR Posting	SP - SAR Posting
IB- Initial Ballot	IC - Initial Ballot
AB - Additional Ballot	AB - Additional Ballot
PB- Presented to BOT	PB - Presented to BOT
F-Projected filing with FI	F - Projected Filing with FERC
PRP- Periodic Review Po	PRP - Periodoc Review Posting
PRR - Periodic Review Recommendation to SC	

Project Status

No Issues with Project
Project Off Schedule by One Quarter
Project Off Schedule by Two or more Quarters
No Development Work in Progress

This worksheet displays estimates of anticipated standards development milestones for projects in 2015, and it is intended to be a project management tool for use in tracking the status of projects under development compared to their anticipated milestones. Detailed information for each project is available from their respective project pages on the NERC website. Projects that remained from 2014's Project Tracking Spreadsheet that were not prioritized in the RSDP, but that are continuing beyond the first quarter of 2015, are also represented here. Projects not anticipated to continue beyond the first quarter of 2015 are not included (information for those projects remains available under the "Standards Under Development" page on the NERC website). Note that projects listed here represent known projects for 2015. As facts and circumstances warrant, it may be necessary to update this tool, and additional projects may be added in response to regulatory directives, input from RISC, or to meet goals of the NERC strategic plan.

Projected Posting Schedule

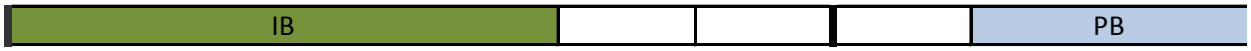
The above is a link to the schedule of upcoming postings, which is updated weekly. It includes near term posting projections.

Project Number	Activity/Project (Project Names Hyperlinked to Project Page)	Deliverable	Deadline, if any	Comments	PMOS Liaison	NERC Contact	Status: Green, Yellow, Red	Milestones: Planned vs. Actual/Projected (See Notes 3 and 4)	2015 JAN	2015 FEB	2015 MAR	2015 APR	2015 MAY	2015 JUN	2015 JUL	2015 AUG	2015 SEP	2015 OCT	2015 NOV	2015 DEC	2016 JAN	2016 FEB	2016 MAR	2016 APR	2016 MAY	2016 JUN	2016 JUL	2016 AUG	2016 SEP	2016 OCT	2016 NOV	2016 DEC
									First Quarter			Second Quarter			Third Quarter			Fourth Quarter			First Quarter			Second Quarter			Third Quarter			Fourth Quarter		
2007-06	System Protection Coordination	PRC-027		Passed ballot with 69.76% (84.34% Quorum) Anticipates final ballot October 2015.	Jennifer Sterling	Al McMeekin	Project extended to address an additional issue by FERC	2015 PMOS Plan			AB			AB		PB		F												
								Actual/Projected				AB				AB			AB	PB	F										
2007-06.2	Phase 2: System Protection Coordination	PRC-001-1.1.(ret.), TOP-009-1	NERC-imposed deadline of	Did not pass Septmber 2015 ballot and will plan to conduct another SDT meeting and post for additional ballot. Goal to post week of Oct. 5	Brenda Hampton	Scott Barfield		2015 PMOS Plan						IB		AB			PB		QQA2										
								Actual/Projected								IB			AB	PB	F										
2008-02.2	Undervoltage Load Shedding for PRC-004	PRC-004 and PRC-010		A 45-day additional comment period and ballot are open until April 7.	Jennifer Sterling	Scott Barfield		2015 PMOS Plan			IB		PB		F																
								Actual/Projected			IB		PB		F																
2009-02	Real-time Reliability Monitoring and Analysis Capabilities	TOP-010, IRO-018		To be presented at the September 23 SC meeting for authorization of posting.	Jennifer Sterling	Mark Olson	Phased to start after TOP/IRO Project 2014-03 completion	2015 PMOS Plan				SP		IB		AB			AB			PB		F							
								Actual/Projected							SP		IB			AB		PB		F							
2010-05.3	Phase 3 of Protection System Misoperations: RA$	Revised Definition of Remedial Action Scheme		Project 2010-05.2 Phase 2 of Protection Systems was separated into two phases. In Phase 1, the SPSSDT developed a revised definition for the term Remedial Action Scheme (RAS) which was adopted by the NERC BOT in November 2014. Phase 2 will address the six SPS/RAS-related Reliability Standards. The standards will be consolidated and will address all aspects of SPS/RAS. The SDT began standards development in January and has meetings scheduled for February, March, April, and July.	Colt Norrish	Al McMeekin		2015 PMOS Plan				IB			AB		AB						PB		F							
								Actual/Projected					Informal				IB			AB		PB		F							
2010-14.1	Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-002		Passed additional ballot in August and plan to move forward to final ballot.	Ron Parsons	Darrel Richardson		2015 PMOS Plan		AB			PB		F																
								Actual/Projected		AB					AB					PB	F										
BAL-005 and BAL-006	BAL-005 and BAL-006	BAL-005	N/A	Meeting week of October 12, 2015.	Ken Goldsmith	Darrel Richardson		2015 PMOS Plan		IB			PB		F						F										
								Actual/Projected								IB				PB	F										
2010-14.2.1	BAL-005 and BAL-006	BAL-006	N/A	Meeting week of October 12, 2015.	Ken Goldsmith	Darrel Richardson		2015 PMOS Plan		IB			PB		F					PB											
								Actual/Projected									Survey		AB			PB		F							
2010-14.2.2	BAL-004	BAL-004		Meeting week of September 21, 2015.	Ken Goldsmith	Darrel Richardson		2015 PMOS Plan		PRP		PRP																			
								Actual/Projected				SP				Survey		IB		PB	F										
2015-06	IRO Review	IRO-006-East, IRO-009		Final ballot through July 31 and will be presented to the NERC Board in August. IRO-006-EAST received 90.35% and IRO-009 received 97.50% approvals on the additional ballots.	Charles Yeung	Katherine Street		2015 PMOS Plan				PRP		PRP		PRR																
								Actual/Projected				SP		IB		AB			PB												

2014-01	Dispersed Generation Resources	PRC-005		PRC-005-5 posted for final ballot until March 11. Presented at May Board.	Jennifer Sterling	Katherine Street		2015 PMOS Plan Actual/Projected
2014-04	Physical Security Directives	CIP-014		The standard passed the ballot and was adopted by the NERC BOT in May, 2015. A petition for approval of CIP-014-2 was filed with FERC on May 15, 2015.	Brian Murphy	Steve Crutchfield		2015 PMOS Plan Actual/Projected
2015-01	TPL Directive	TPL-001		This project has been put on hold indefinitely due to data collecting requirements.	Ron Parsons	Steve Crutchfield		2015 PMOS Plan Actual/Projected
2015-02	Emergency Operations Periodic Review	EOP-004, EOP-005, EOP-006, and EOP-008		Final recommendations and a proposed SAR were presented to the SC in July.	Ken Goldsmith	Laura Anderson		2015 PMOS Plan Actual/Projected
2015-03	Periodic Review of System Operating Limit Standards	FAC-010, FAC-011, and FAC-014		Drafting team met July 14-16, 2015. Final recommendations and SAR expected to be presented to the August SC.	Brian Murphy	Mark Olson		2015 PMOS Plan Actual/Projected
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the Rules of	Glossary Terms		Passed final ballot sept. 14, 2015.	Andrew Gallo	Lacey Ourso		2015 PMOS Plan Actual/Projected
2007-17.4	PRC-005 Order No. 803 Directive	PRC-005		Passed ballot and anticipates a final ballot in October 2015.	Charles Yeung	Steve Crutchfield		2015 PMOS Plan Actual/Projected
2010-04.1	MOD-031 Order No. 804 Directives	MOD-031		Passed initial ballot and determining final ballot dates.	Brian Murphy	Darrel Richardson		2015 PMOS Plan Actual/Projected
2015-07	COM-001 Order No. 808 Directive	COM-001-3		Draft COM-001-3 being presented to SC on Sept. 23 for authorization of initial posting.	Brenda Hampton	Sean Bodkin and Jordan Mallory		2015 PMOS Plan Actual/Projected
2015-08	Emergency Operations	EOP-004, EOP-005, EOP-006, and EOP-008		First SDT meeting week of September 28, 2015.	Ken Goldsmith	Laura Anderson		2015 PMOS Plan Actual/Projected
2010-07.1	Vegetation Management	FAC-003		Submitted for appointment of SDT at Sept. SC meeting.	Andrew Gallo	Jordan Mallory/Sean Bodkin		2015 PMOS Plan Actual/Projected
2014-02	CIP Version 5 Revisions	CIP Standards		NOPR issued. Pending Final Rule.	Brian Murphy	Steve Crutchfield		2015 PMOS Plan Actual/Projected
2013-03	Geomagnetic Disturbance Mitigation	TPL-007-1		NOPR issued. Pending Final Rule.	Jennifer Sterling	Mark Olson		2015 PMOS Plan Actual/Projected
2014-03	TOP/IRO Revisions	TOP and IRO standards		NOPR issued. Pending Final Rule.	Brian Murphy	Mark Olson		2015 PMOS Plan Actual/Projected
2015-09	Establish and Communicate System Operating Limits	FAC-010, FAC-011, and FAC-014		Team expected to be appointed Sept 23. Project stems from periodic review.	Andrew Gallo	Lacey Ourso		2015 PMOS Plan Actual/Projected

Project Number	Activity/Project (Project Names Hyperlinked to Project Page)	Deliverable	PMOS Liaison	NERC Contact
2007-06	System Protection Coordination	PRC-027	Jennifer Sterling	Al McMeekin
2007-06.2	Phase 2: System Protection Coordination	PRC-001-1.1., TOP-009-1	Brenda Hampton	Scott Barfield
2010-14.1	Phase 1 of Balancing Authority Reliability based Controls: Reserves	BAL-002	Ron Parsons	Darrel Richardson
2010-14.2.1	BAL-005 and BAL-006	BAL-005 and BAL-006	Ken Goldsmith	Darrel Richardson

Additional Information regarding delay of project
Project extended to address an issue raised by FERC. Project passed additional ballot and will be posted for final ballot in October 2015.
Did not pass Septmber 2015 ballot and will plan to conduct another SDT meeting and post for additional ballot. Goal to post week of Oct. 5, 2015.
Project extended to address an additional issues by FERC.
Difficulty in scheduling SDT meetings.


IB
PB

		F

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Projected Posting Schedule

Below is a schedule of upcoming postings so you have the opportunity to schedule time with appropriate subject matter experts in your organizations to review these standards and ensure that balloters will be available during the ballot windows or have assigned proxies. The projected schedule is subject to change. For a high-level view of the planned schedule for all active projects, including information regarding the number of paragraph 81 requirements, directives, and guidances, please see the Project Tracking Spreadsheet on the Standards page.

Week of November 30:

- Final ballot
  - 2010-14.2.2 Phase 2 of BARC BAL-004

Week of December 7:

- 45-day comment period and additional ballot
  - 2009-02 Real-time Reliability Monitoring & Analysis Capabilities

Weeks of December 14, 21, and 28: None

Week of January 4, 2016: None

Week of January 11, 2016: None

**Please note that the dates in the chart below are estimates and are subject to change.

Projects	11/30	12/7	12/14	12/21	12/28	1/4	Closing Date
2007-06.2 Phase 2 of System Protection Coordination TOP-009							
2008-02.2 Phase 2 of UVLS: Misoperations PRC-004, PRC-010							
2009-02 Real-time Reliability Monitoring & Analysis Capabilities TOP-010		12/9					1/22
2009-02 Real-time Reliability Monitoring & Analysis Capabilities IRO-018		12/9					1/22
2010-05.3 Phase 3 of Protection Systems: RAS							1/8
2010-07.1 Vegetation Management FAC-003			12/16				
2010-14.2.1 Phase 2 of BARC BAL-005, FAC-001-3							1/11
2010-14.2.1 Phase 2 of BARC BAL-006							1/11
2010-14.2.2 Phase 2 of BARC BAL-004							
2015-07 Internal Communications Capabilities COM-001							
2015-08 Emergency Operations EOP-004							
2015-08 Emergency Operations EOP-005							
2015-08 Emergency Operations EOP-006							
2015-08 Emergency Operations EOP-008							
2015-09 System Operating Limits FAC-010							
2015-09 System Operating Limits FAC-011							
2015-09 System Operating Limits FAC-014							
2015-10: Single Points of Failure TPL-001 SAR			12/17				
2015-10: Single Points of Failure TPL-001 Nomination Solicitation	12/1						
Number of Standards Posted	5	7	7	5	5	5	

	Nomination solicitation
	30-day comment period
	45-day comment period and ballot/additional ballot
	45-day comment period
	Final ballot

RSC Meeting #15-5, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Ongoing
4.2	Lee Pedowicz needs to come up with a way to identify the group names in the Balloting and Commenting System	Lee Pedowicz	RSC Meeting	Ongoing
4.3	Solicit RSC meeting for 2016 Combine meeting with CC for June 2016 at Saratoga Springs	Lee Pedowicz	RSC Meeting	Ongoing

DRAFT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Weekly Standards & Compliance Bulletin

November 30–December 6, 2015

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2010-07.1 Vegetation Management – FAC-003-4	Initial Ballot	12/07/15	12/16/15
NEW Project 2010-05.3 – Phase 3 of Protection Systems: Remedial Action Schemes (RAS) – PRC-012-2 and Proposed Definition	Initial Ballot, Additional Ballot, and Non-binding Poll	12/30/15	1/08/16
Project 2010-14.2.1 – Phase 2 of Balancing Authority Reliability-based Controls – BAL-005, BAL-006, FAC-001	Additional Ballot and Non-binding Poll	12/31/15	1/11/16
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2010-07.1 Vegetation Management – FAC-003-4	Join Ballot Pool	10/30/15	11/30/15
Posted for Comment (comment periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2010-07.1 Vegetation Management – FAC-003-4 Draft RSAW posted for comment through December 16, 2015. Submit comments to RSAWfeedback@nerc.net.	Comment Form	10/30/15	12/16/15
Project 2015-10 – Single Points of Failure – TPL-001	Comment Form	11/12/15	12/17/15
NEW Project 2010-05.3 – Phase 3 of Protection Systems: Remedial Action Schemes (RAS) – PRC-012-2 and Proposed Definition	Comment Form	11/25/15	1/08/16
Project 2010-14.2.1 – Phase 2 of Balancing Authority Reliability-based Controls – BAL-005, BAL-006, FAC-001	Comment Form	11/10/15	1/11/16

NEW Draft RSAWs for BAL-005-1 and FAC-001-3 are posted for comment through January 11, 2016. Submit feedback regarding the draft RSAWs to RSAWfeedback@nerc.net.			

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Regional Reliability Standards Available for Comment: WECC has requested NERC to post Regional Reliability Standards **MOD-026-2** and **MOD-027-2 – Modeling, Data, and Analysis (WECC Variance)** for a 45-day industry review and comment period as permitted by the NERC Rules of Procedure.	Submit comments using the comment form.	11/13/15	12/28/15

GENERAL STANDARDS NEWS

There is no additional Standards news 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
2015–2017 Reliability Standards Development Plan

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW Four New RSAWs Released

NERC has posted new Reliability Standard Audit Worksheets (RSAWs) for FAC-001-2, FAC-002-2, NUC-001-3, and PRC-005-4 to the RSAW homepage under the heading 'Current RSAWs for Use.' All four standards become effective on January 1, 2016.

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, 2016	FAC-001-2 – Facility Interconnection Requirements; FAC-002-2 – Facility Interconnection Studies; NUC-001-3 – Nuclear Plant Interface Coordination; PRC-005-4 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
April 1, 2016	CIP-002-5.1 – Cyber Security – BES Cyber System Categorization; CIP-003-5 – Cyber Security – Security Management Controls; CIP-004-5.1 – Cyber Security – Personnel & Training; CIP-005-5 – Cyber Security – Electronic Security Perimeter(s); CIP-006-5 – Cyber Security – Physical Security of BES Cyber Systems; CIP-007-5 – Cyber Security – System Security Management; CIP-008-5 – Cyber Security – Incident Reporting and Response Planning; CIP-009-5 – Cyber Security – Recovery Plans for BES Cyber Systems; CIP-10-1 – Cyber Security – Configuration Change Management and Vulnerability Assessments; CIP-011-1 – Cyber Security – Information Protection; PRC-005-3 – Protection System and Automatic Reclosing Maintenance*; PRC-005-3(i) – Protection System and Automatic Reclosing Maintenance*
July 1, 2016	BAL-001-2 – Real Power Balancing Control Performance; COM-002-4 – Operating Personnel Communications Protocols; MOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability and

	Synchronous Condenser Reactive Power Capability; MOD-031-1 – Demand and Energy Data; PER-005-2 – Operations Personnel Training; PRC-004-4 – Protection System Misoperation Identification and Correction; PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection; PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection; PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings; PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings; PRC-002-2 – Disturbance Monitoring and Reporting Requirements
July 1, 2017	MOD-033-1 – Steady-State and Dynamic System Model Validation

***PLEASE NOTE**: On November 13, 2015, NERC filed with FERC a motion to Defer Implementation and Request for Shortened Response Period and Expedited Action in Docket Nos. RM14-8-000, RD15-3-000, and RM15-9-000 as well as a petition for approval of proposed Reliability Standard PRC-005-6. The motion requests FERC defer the implementation of FERC-approved Reliability Standards PRC-005-3, PRC-005-3(i), and PRC-005-4 from January 1, 2016, until after FERC issues a final order on proposed Reliability Standard PRC-005-6.

The motion requests that should FERC ultimately approve proposed PRC-005-6, FERC continue to defer implementation until the effective date of PRC-005-6 to allow the PRC-005-6 implementation plan to operate as intended. However, should FERC not approve proposed PRC-005-6, NERC requests that FERC defer implementation of PRC-005-3, PRC-005-3(i), and PRC-005-4 an additional six months from the effective date of the Commission's order remanding the proposed standard to allow entities a reasonable amount of time to come into compliance.

BOARD OF TRUSTEES AND FERC ACTION

NEW NERC Filings

On November 23, 2015, NERC submitted to FERC comments in response to the notice of proposed rulemaking for proposed Reliability Standard PRC-026-1 – Relay Performance During Stable Power Swings.

NERC's 2015 filings to FERC are available here.

UPCOMING EVENTS

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

Workshops and Conferences

- Geomagnetic Disturbance Planning Studies Workshop – December 9, 2015, Atlanta | Register

Webinars

- Risk Elements Monthly Webinar Series: Threats to Cyber Systems – 1:00–2:00 p.m. Eastern, December 3, 2015 | Register
- NEW Risk-based Registration Webinar – 1:00–2:30 p.m. Eastern, December 17, 2015 | Register

Standing Committee Meetings and Conference Calls

- Compliance and Certification Committee – December 2–3, 2015, Atlanta | Register
- Standards Committee Conference Call – 8:00 a.m.–1:00 p.m. Pacific, December 9, 2015 | Register
- Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee Meetings – December 15–16, 2015, Atlanta | Register for OC | Register for PC | Register for CIPC

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 Brooke Thornton.

Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 2015-2016

The following Regional Standards Committee (RSC) Work Plan activities planned for the calendar years of 2015 -2016 will be consistent with the NPCC 2015 and 2016 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 and results based standards efforts. Also, the Work Plan is responsive to the NERC Reliability Standards Development Process and ERO strategic goals. In 2015-2016 expedited standards project schedules and enhanced periodic reviews of standards with the goal of achieving "steady-state" will be the focus of the RSC.

Core Reliability Standards Committee Functions

- Coordinate NPCC Regional Standards development activity with the development of standards appearing in the NERC Reliability Standards Development Plan.
- Review, promote, and support the ERO results based standards initiative and ongoing standards development work.
- Promote the results based standards initiative throughout the Northeast.
- Continue to develop a model for consideration of costs in NERC's Standards Development program.
- 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 new continent wide ERO standards.
- Engage in newly approved NERC Application Guidance program. Support the inputs through the NPCC CC regarding the NERC CMEP Guidance Program.
- Monitor NERC's Reliability Issues Steering Committee (RISC) top reliability related issues and priorities for potential incorporation into NERC standards, removal from standards or for incorporation into guidelines or other non-standards solutions. Provide and coordinate NPCC's input into those decisions.
- Address emerging issues FERC might have with the NPCC Regional Standard Processes to promote consistency and support the ERO One Enterprise model.
- 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.
- Promote the NPCC criteria as being more specific or more stringent. Coordinate efforts with the NPCC Compliance Committee to facilitate the 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.
- Coordinate and provide input to the development and prioritization of ERO reliability standards within the NERC Reliability Standards Development Plan.
- 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, and FERC directives.
- 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.
- Develop ballot recommendations or "issues statements" for all NERC standards under development.
- Review and develop ballot recommendations for all NERC Formal Interpretations to standards.

- Identify candidate NERC Standards drafting team members from the NPCC region to provide the NPCC perspective on standards development.
- Provide guidance to NPCC regional standard drafting teams in critical areas of results based standards, Violation Severity Level, and Violation Risk Factor development as well as in ensuring quality.
- Respond to FERC and Provincial filings and interrogatories on issues related to regional standards.
- Serve as a liaison for the Northeast to the NERC Reliability Issues Steering Committee for all new and emerging reliability risks to the BES.
- Participate in the proceedings of various NERC groups to contribute to the continual improvement to NERC standards and processes. These groups include but are not limited to:
    - NERC Standards Committee (SC)
    - NERC Standards Committee Process Subcommittee (SCPS)
    - NERC Project Management Oversight Subcommittee (PMOS)
    - NERC Functional Model Advisory Group (FMAG)
    - NERC SAR and Standards Drafting Teams (SDTs)
    - NERC Reliability Issues Steering Committee (RISC)

NPCC Standard and Directory Activities

- Review the need for and development of the following regional standards and requirements utilizing the NPCC Regional Standard Processes Manual if directed by the ERO or as needed in response to the revision or development of the ERO standard(s):

    - Special Protection Systems Standard
    - Reserve Sharing Groups Standard

- Address any outstanding issues with the regulatory authorities in the U.S. and all applicable Provincial authorities for regional standards or NPCC directories.
- Address any outstanding issues with the regulatory authorities in the U.S. and all applicable Provincial authorities for Regional Standards Authorization Requests (RSARs).
- Review and initiate action on RSARs upon their acceptance by NPCC's Regional Standards Process Manager.
- Develop proposed standards utilizing regional technical committees as assigned by the NPCC RCC.
- Work with the NPCC CC to develop the necessary compliance elements of the regional standards, for example, Violation Severity Levels (VSLs).
- Coordinate directory criteria requirements with regional standards requirements to ensure no inconsistencies exist and identify potential areas for improvements.
- 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.
- Develop filings of directories as required with the Provincial regulators as per the various Memorandums of Understanding.
- Review NERC SARs, standards, and interpretations, and provide comments as well as participate in the NERC process.
- Ensure that the appropriate NPCC Task Forces review NERC issuances, and provide input to support a consensus opinion.
- Solicit technically qualified candidates from NPCC to participate on each of the NERC drafting teams and additional members to the regional drafting teams. Ensure sufficient regional representation exists on the drafting teams.
- Review FERC rulings and communicate the rulings to the NPCC Members and coordinate the response to issues for the Members.
- Participate in ballots for ERO standards and provide recommended comments and ballot positions to the NPCC Members of the NERC Registered Ballot Body.
- Educate and notify stakeholders and regulators about issues related to standards development.

- Provide a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task Force on Infrastructure Security and Technology (TFIST), and other NPCC Task Forces and Working Groups.
- Achieve NPCC reliability goals and objectives by initiating and efficiently completing standards development activities.
- Leverage internet and web-based tool functionality to ensure interregional consistency, uniformity, and quality of regional reliability standards.
- Establish a long-term strategy for standards improvement and initiate implementation.
- Ensure the topics addressed by the reliability standards reflect changing industry needs.
- Identify potential market issues for regional standards through NPCC Reliability Coordinating Committee (RCC) reviews.
- Process Improvement
    - Coordinate implementation of the NERC standards development process and NPCC regional standard process and recommend revisions as necessary.
    - Participate in the revision and redrafting of the NERC rules and procedures related to standards development such as, but not limited to:
        - The NERC Functional Model Working Group (FMWG)
        - The NERC Regional Standards Group (RSG)
        - The NERC Standards Committee (SC)
        - The NERC Standards Committee Process Subcommittee (SCPS)
    - Establish goals/targets for NERC and NPCC standards procedure improvement.
- Streamline and improve the regional standards process and continue to enhance program tools.
- Communications
    - Strengthen the relationship with the industry's technical committees to ensure adequate input to standards development.
    - Sponsor NPCC Workshops and participate in NERC Workshops to promote awareness and educate the industry in standards-related activities.
    - Promote the reliability objectives of the NERC standards as appropriate to the NPCC Members of the NERC Registered Ballot Body.
    - Educate and inform industry stakeholders through web-based tools such as "Webinars" and participation in NERC Reliability Standards Workshops, as necessary.
    - Update and inform governmental regulators and/or authorities on the standards development work plan and processes through individual project discussions and NPCC meetings/conferences.
    - Develop standards program communications that support NERC's overall communications platform.
    - Develop and maintain NPCC Reliability Directories and NPCC guidance documents which will enable users, owners and operators of the international Bulk Power System in the Region the ability to apply reliability requirements in NERC and NPCC as well as the more stringent NPCC regionally-specific criteria.
    - Identify future regional standard opportunities by developing a set of regional reliability directories incorporating the ERO reliability standards, regional standards and regionally-specific more stringent criteria.
    - Accomplish all directives of ERO and governmental and/or regulatory authorities with regard to regional standards development and procedures.
    - Adhere to and surpass the ERO Reliability Standards Work Plan milestones, when practical, as they pertain to targets for the regional standards.

RSC 2015-2016 Deliverables

- Solicit and develop comments to all NERC reliability standards related postings, highlighting issues detrimental to the reliability of the Northeast and develop consensus suggestions to address those issues.
- Coordinate and oversee the review of the NPCC regional standards based on FERC approved NERC

standards and potential revisions and retirements to NPCC's standards.

- Develop ballot recommendations and/or issues notifications for all posted NERC standards ballots.
- Review NPCC Directory criteria to ensure consistency with NERC Reliability Standards
- Participate in further development and application of the NERC Cost Considerations Porcess
- Participate in two NPCC Standards and Compliance Workshops.
- Participate in two NERC Standards Workshops.

Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 2015-2016

The following Regional Standards Committee (RSC) Work Plan activities planned for the calendar years of 2015 -2016 will be consistent with the NPCC 2015 and 2016 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 and results based standards efforts. Also, the Work Plan is responsive to the NERC Reliability Standards Development Process and ERO strategic goals. In 2015-2016 expedited standards project schedules and enhanced periodic reviews of standards with the goal of achieving "steady-state" will be the focus of the RSC.

Core Reliability Standards Committee Functions

- Review, promote, and support the ERO results based standards initiative and ongoing standards development work.
- Promote the results based standards initiative throughout the Northeast.
- Continue to promote NERC's adoption of its Cost Effective Analysis Process which is based on the NPCC Cost Effective Analysis Procedure.
- Review and participate in the regional standards development process, and base any development or revision of NPCC Regional Reliability Standards on the reliability related needs of the Region or new continent wide ERO standards.
- Coordinate NPCC Regional Standards development with the development of standards appearing in the NERC Reliability Standards Development Plan.
- Monitor NERC's Reliability Issues Steering Committee (RISC) top reliability related issues and priorities for potential incorporation into NERC standards, removal from standards or for incorporation into guidelines or other non-standards solutions. Provide and coordinate NPCC's input into those decisions.
- Coordinate NPCC participation in the review and the revision of NERC Standards per Order 693 addressing directives from FERC and any Provincial regulatory directives through the Enhanced Periodic Review process.
- Address emerging issues FERC might have with the NPCC Regional Standard Processes to promote consistency and support the ERO One Enterprise model.
- 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.
- Promote the NPCC criteria as being more specific or more stringent. Coordinate efforts with the NPCC Compliance Committee to facilitate the 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.
- Coordinate and provide input to the development and prioritization of ERO reliability standards within the NERC Reliability Standards Development Plan.
- 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, and FERC directives.
- 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.
- Develop ballot recommendations or "issues statements" for all NERC standards under development.

- Review and develop ballot recommendations for all NERC Formal Interpretations to standards.
- Provide guidance for NPCC regional standard drafting teams in critical areas of results based standards, Violation Severity Level, and Violation Risk Factor development as well as in ensuring quality.
- Respond to FERC and Provincial filings and interrogatories on issues related to regional standards.
- Serve as a liaison for the Northeast to the NERC Reliability Issues Steering Committee for all new and emerging reliability risks to the BES.
- Participate in the proceedings of various NERC groups to contribute to the continual improvement to NERC standards and processes. These groups include but are not limited to:
    - NERC Standards Committee (SC)
    - NERC Standards Committee Process Subcommittee (SCPS)
    - NERC Project Management Oversight Subcommittee (PMOS)
    - NERC Functional Model Advisory Group (FMAG)
    - NERC SAR and Standards Drafting Teams (SDTs)
    - NERC Reliability Issues Steering Committee (RISC)

NPCC Standard and Directory Activities

- Review the need for and development of the following regional standards and requirements utilizing the NPCC Regional Standard Processes Manual if directed by the ERO or as needed in response to the revision or development of the ERO standard(s):

    - Special Protection Systems Standard
    - Reserve Sharing Groups Standard

- Develop any required responses to regulatory inquiry for the NPCC Regional Disturbance Monitoring Standard and the Automatic Underfrequency Load Shedding Program Standard. Provide to FERC and the applicable Provincial regulatory authorities for their information or approvals, as may be required, i.e. data requests, filings to address directives etc., and review the need to revise or retire the standard(s) in the context of the ERO revised Disturbance Monitoring or Underfrequency Load Shedding Standards. The RSC will initiate action on the potential revisions or retirements.
- Address any outstanding issues with the regulatory authorities in the U.S. and all applicable Provincial authorities for regional standards or NPCC directories.
- Address any outstanding issues with the regulatory authorities in the U.S. and all applicable Provincial authorities for Regional Standards Authorization Requests (RSARs).
- Review and initiate action on RSARs upon their acceptance by NPCC's Regional Standards Process Manager.
- Produce initial drafts of new or revised regional standards for Drafting Teams to begin work with.
- Develop proposed standards utilizing regional technical committees as assigned by the NPCC RCC.
- Work with the NPCC CC to develop the necessary compliance elements of the regional standards, for example, Violation Severity Levels (VSLs).
- Coordinate directory criteria requirements with regional standards requirements to ensure no inconsistencies exist and identify potential areas for improvements.
- 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.
- Develop filings of directories as required with the Provincial regulators as per the various Memorandums of Understanding.
- Implement technical aspects related to the implementation of the Energy Policy Act of 2005, focusing on standards/criteria development, and related FERC and ERO requirements.
- Implement the NPCC Cost Effective Analysis Procedure and apply to regional standards and directories being revised or developed, and promote and participate in the NERC Cost Effective Analysis Process application to the ERO draft continent-wide standards.

- Review NERC SARs, standards, and interpretations, and provide comments as well as participate in the NERC process.
- Ensure that the appropriate NPCC Task Forces review NERC issuances, and provide input to support a consensus opinion.
- Solicit technically qualified candidates from NPCC to participate on each of the NERC drafting teams and additional members to the regional drafting teams. Ensure sufficient regional representation exists on the drafting teams.
- Review FERC rulings and communicate the rulings to the NPCC Members and coordinate the response to issues for the Members.
- Participate in ballots for ERO standards and provide recommended comments and ballot positions to the NPCC Members of the NERC Registered Ballot Body.
- Educate and notify stakeholders and regulators about issues related to standards development.
- Provide a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task Force on Infrastructure Security and Technology (TFIST), and other NPCC Task Forces and Working Groups.
- Achieve NPCC reliability goals and objectives by initiating and efficiently completing standards development activities.
- Leverage internet and web-based tool functionality to ensure interregional consistency, uniformity, and quality of regional reliability standards.
- Establish a long-term strategy for standards improvement and initiate implementation.
- Ensure the topics addressed by the reliability standards reflect changing industry needs.
- Identify potential market issues for regional standards through NPCC Reliability Coordinating Committee (RCC) reviews.
- Process Improvement
    - Coordinate implementation of the NERC standards development process and NPCC regional standard process and recommend revisions as necessary.
    - Participate in the revision and redrafting of the NERC rules and procedures related to standards development such as, but not limited to:
        - The NERC Functional Model Working Group (FMWG)
        - The NERC Regional Standards Group (RSG)
        - The NERC Standards Committee (SC)
        - The NERC Standards Committee Process Subcommittee (SCPS)
    - Establish goals/targets for NERC and NPCC standards procedure improvement.
- Streamline and improve the regional standards process and continue to enhance program tools.
- Communications
    - Strengthen the relationship with the industry's technical committees to ensure adequate input to standards development.
    - Sponsor NPCC Workshops and participate in NERC Workshops to promote awareness and educate the industry in standards-related activities.
    - Promote the reliability objectives of the NERC standards as appropriate to the NPCC Members of the NERC Registered Ballot Body.
    - Educate and inform industry stakeholders through web-based tools such as "Webinars" and participation in NERC Reliability Standards Workshops, as necessary.
    - Update and inform governmental regulators and/or authorities on the standards development work plan and processes through individual project discussions and NPCC meetings/conferences.
    - Develop standards program communications that support NERC's overall communications platform.
    - Develop and maintain NPCC Reliability Directories and NPCC guidance documents which will enable users, owners and operators of the international Bulk Power System in the Region the ability to apply reliability requirements in NERC and NPCC as well as the more stringent NPCC regionally-specific criteria.
    - Identify future regional standard opportunities by developing a set of regional reliability directories incorporating the ERO reliability standards, regional standards and regionally-specific more stringent criteria.
    - Accomplish all directives of ERO and governmental and/or regulatory authorities with regard

to regional standards development and procedures.
- Adhere to and surpass the ERO Reliability Standards Work Plan milestones, when practical, as they pertain to targets for the regional standards.

RSC 2015-2016 Deliverables

- Solicit and develop comments to all NERC reliability standards related postings, highlighting issues detrimental to the reliability of the Northeast and develop consensus suggestions to address those issues.
- Coordinate and oversee the review of the NPCC regional standards based on FERC approved NERC standards (i.e. Disturbance Monitoring and Underfrequency Load Shedding) and potential revisions and retirements to NPCC's standards.
- Develop ballot recommendations and/or issues notifications for all posted NERC standards ballots.
- Review NPCC Directory criteria to ensure consistency with NERC Reliability Standards (ex. SPS to RAS)
- Participate in further development and application of the NERC Cost Effective Analysis Process.
- Participate in two NPCC Standards and Compliance Workshops.
- Participate in two NERC Standards Workshops.

NPCC, Inc.
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Approved by NPCC Board of Directors X--2015

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 Process.
(c) Providing consolidated NPCC Regional review and comment to the existing and proposed NERC Standards and participating in the NERC Reliability Standards Development Process.
(d) Reviewing the FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) related to reliability Standards, providing a forum for developing consensus viewpoints, and submitting comments to FERC, as necessary.
(e) Reviewing NERC Reliability Standard Audit Worksheets working in coordination with the NPCC Compliance Committee (CC) and submitting comments to NERC, as necessary.
(f) Providing, as necessary, 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 Standards interpretation and interpretations and NPCC Standards and Directory/Criteria clarifications.
(h) Providing a forum for sharing viewpoints and opinions with the goal of achieving consensus regarding reliability attributes of various forms of guidance and regulation.

After receiving input from any or all NPCC groups and for all submissions of standards related comments on behalf of NPCC, the RSC will be the only body submitting those comments to FERC, NERC, or any other industry entities.

The RSC is an open and balanced stakeholder committee inclusive of all stakeholders that provide for or are materially impacted by the reliability of the Bulk Power 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 NPCC Standards Staff which will administer the NPCC Regional Standards Process and coordinate the review and submission of comments.

The RSC will be chaired by a member of NPCC Standards Program Area Staff who will be assisted by the NPCC Regional Standards Process Manager (also a member of NPCC Staff) along with co-vice chairs elected by the RSC from the existing members of the Committee at the time the vote is taken. Co-vice chairs nominations 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 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, a Canadian representative, and a U.S. representative. The two RSC members elected by RSC membership will serve for one year terms.

Members of the RSC will be nominated by their respective companies. NPCC RSC leadership 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 leadership. 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 and 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 for carrying out their responsibilities in accordance with this document.

RSC Members are to represent their companies and sectors, and work to resolve differences with an overarching perspective which maintains, or improves 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 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 from the same segment. RSC business cannot be conducted in the absence of a quorum, and it is essential that each RSC member make a commitment to being present.

A. NPCC Regional Standards Process Responsibilities

The RSC is responsible for managing the standards process for development of standards, Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), definitions, variances,

interpretations, and clarifications in accordance with the NPCC Regional Standard Processes Manual. 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 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 manages and has oversight of the development processes for NPCC Directories and the Criteria within each document. The RSC is also responsible for ensuring that the content of each Directory is consistent with the overall objectives of the NPCC Directory project. The RSC will provide guidance to all NPCC Committees regarding the development of NPCC documents.

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 and coordinate the submission of NPCC comments to existing and developing NERC Reliability Standards when posted for NERC "Open Process Review."
- Provide a forum for NPCC to participate, solicit, and provide Regional comments as new Standard Authorization Requests (SARs), and their respective Reliability Standards, are developed in accordance with the NERC Standard Development Processes Manual.
- Provide a forum for NPCC to participate, solicit, and provide Regional comments from a reliability perspective on Reliability Standard Audit Worksheets (RSAW) after receiving CC input.
- Identify prospective reliability issues associated with new NERC Reliability Standards and their potential impact on the NPCC Region, (i.e. Regional Difference), Regional standards, Directories and Criteria.
- 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 Standards drafting teams.
- Develop and maintain a Web-Based Database for tracking and scheduling Standards development activities from a Regional perspective.
- Target a wider range of participants in the standard commenting process. 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 pointers to 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 NPCC contributions to the NERC Application Guidance Process for

Standards compliance application

D. FERC Activities Affecting Standards

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

When called upon, participate in technician conferences hosted by NERC, FERC or other regions on topics of importance to power system reliability.

Standards Committee Expectations

Approved by Standards Committee January 12, 2012

Background

Standards Committee (SC) members are elected by members of their segment of the Registered Ballot Body, to help the SC fulfill its purpose. According to the Standards Committee Charter, the SC's purpose is:

> *In compliance with the NERC Reliability Standards Development Procedure, the Standards Committee manages the NERC standards development process for the North American-wide reliability standards with the support of the NERC staff to achieve broad bulk power system reliability goals for the industry. The Standards Committee protects the integrity and credibility of the standards development process.*

The purpose of this document is to outline the key considerations that each member of the SC must make in fulfilling his or her duties. Each member is accountable to the members of the Segment that elected them, other members of the SC, and the NERC Board of Trustees for carrying out their responsibilities in accordance with this document.

Expectations of Standards Committee Members

1. SC Members represent their segment, not their organization or personal views. Each member is expected to identify and use mechanisms for being in contact with members of the segment in order to maintain a current perspective of the views, concerns, and input from that segment. NERC can provide mechanisms to support communications if an SC member requests such assistance.
2. SC Members base their decisions on what is best for reliability and must consider not only what is best for their segment, but also what is in the best interest of the broader industry and reliability.
3. SC Members should make every effort to attend scheduled meetings, and when not available are required to identify and brief a proxy from the same segment. Standards Committee business cannot be conducted in the absence of a quorum, and it is essential that each Standards Committee make a commitment to being present.
4. SC Members should not leverage or attempt to leverage their position on the SC to influence the outcome of standards projects.
5. The role of the Standards Committee is to manage the standards process and the quality of the output, not the technical content of standards.

Order No. 693 Citation	Directive/Guidance	Resolution
P 905-906	Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.	Proposed IRO-018-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the Reliability Coordinator's (RC) monitoring and analysis capabilities. The monitoring and analysis capabilities required by proposed IRO-018-1 and other IRO standards discussed below ensure RCs have the capabilities to maintain Real-time situational awareness. **Monitoring Capabilities** Requirements R1 and R2 address the quality of the Real-time data needed by the RC to perform its monitoring and Real-time Assessments. Each RC is required to implement a documented procedure for addressing Real-time data quality issues, including invalid or time-late data, and must provide System Operators with information to indicate the quality of data received. Requirement R5 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring RCs to use an independent alarm process monitor. Requirements for the RC to perform Real-time monitoring are specified in currently-enforceable IRO-002-2, IRO-003-2, and proposed IRO-002-4 from Project 2014-03. ***Proposed IRO-018-1*** **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

Order No. 693 Citation	Directive/Guidance	Resolution
		monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: **1.1.** Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to: **1.1.1.** Data outside of a prescribed data range; **1.1.2.** Analog data not updated within a predetermined time period; **1.1.3.** Data entered manually to override telemetered information; and **1.1.4.** Data otherwise identified as invalid or suspect. **1.2.** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. **R2.** Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. **R5.** Each Reliability Coordinator shall utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***Currently-enforceable IRO-002-2*** **R5.** Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be

Order No. 693 Citation	Directive/Guidance	Resolution
		critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. ***Currently-enforceable IRO-003-2*** **R1.** Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. ***Proposed IRO-002-4 (pending regulatory approval)*** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Analysis Capabilities** Requirements R3 and R4 address the quality of the analysis used by the RC to perform its Real-time Assessments. Each RC is required to implement a documented procedure to maintain the quality of the analysis used in its Real-time Assessments and must provide System Operators with information to indicate the quality of this analysis.

Order No. 693 Citation	Directive/Guidance	Resolution
		Requirements for the RC to perform Real-time Assessments are specified in currently-enforceable IRO-008-1 and proposed IRO-008-2. ***Proposed IRO-018-1*** **R3.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: **3.1.** Criteria for evaluating the quality of any analysis used in its Real-time Assessments; and **3.2.** Actions to resolve quality deficiencies in any analysis used in its Real-time Assessments. **R4.** Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. ***Currently-enforceable IRO-008-1*** **R2.** Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. ***Revised definition of Real-time Assessment (pending regulatory approval)*** 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

Order No. 693 Citation	Directive/Guidance	Resolution
		identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) ***Proposed IRO-008-2 (pending regulatory approval)*** **R4.** Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
P 1660	We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.	Proposed TOP-010-1 addresses issues identified by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF) related to the availability and quality of the monitoring and analysis capabilities used by Transmission Operators (TOPs) and Balancing Authorities (BAs). The monitoring and analysis capabilities required by proposed TOP-010-1 and other TOP standards discussed below ensure TOPs and BAs have the capabilities to maintain Real-time situational awareness. **<u>Monitoring Capabilities</u>** Requirements R1 through R4 address the quality of the Real-time data needed by TOPs and BAs to perform their Real-time monitoring and Real-time analysis. Each TOP and BA is required to implement a documented procedure for addressing Real-time data quality issues, including invalid or time-late data, and must provide System Operators with information to indicate the quality of data received. Requirement R7 addresses capabilities for operator awareness of failures in Real-time monitoring alarm processes by requiring TOPs and BAs to use an independent alarm process monitor. Requirements for TOPs to perform Real-time monitoring are specified in currently-enforceable TOP-006-2 and proposed TOP-001-3 from Project 2014-03.

Order No. 693 Citation	Directive/Guidance	Resolution
		Requirements for BAs to perform Real-time monitoring are specified in currently-enforceable TOP-006-2, proposed TOP-001-3 from Project 2014-03, and BAL standards. ***Proposed TOP-010-1*** **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: **1.1.** Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to: **1.1.1.** Data outside of a prescribed data range; **1.1.2.** Analog data not updated within a predetermined time period; **1.1.3.** Data entered manually to override telemetered information; and **1.1.4.** Data otherwise identified as invalid or suspect. **1.2.** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. **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: **2.1** Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to: **2.1.1.** Data outside of a prescribed data range;

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		2.1.2. Analog data not updated within a predetermined time period; **2.1.3.** Data entered manually to override telemetered information; and **2.1.4.** Data otherwise identified as invalid or suspect. **2.2** Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data. **R3.** Each Transmission Operator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. **R4.** Each Balancing Authority shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. **R7.** Each Transmission Operator and Balancing Authority shall utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. ***Currently-enforceable TOP-006-2*** **R1.** Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. **1.1.** - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. **1.2.** - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission

Order No. 693 Citation	Directive/Guidance	Resolution
		Operators of all generation and transmission resources available for use. ***Proposed TOP-001-3 (pending regulatory approval)*** **R10.** Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: **10.1.** Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and **10.2.** Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems. **R11.** Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency. **<u>Analysis Capabilities</u>** Requirements R5 and R6 address the quality of the analysis used by the TOP to perform its Real-time Assessments. Each TOP is required to implement a documented procedure to maintain the quality of the analysis used in its Real-time Assessments and must provide System Operators with information to indicate the quality of this analysis. Requirements for the TOP to perform Real-time Assessments are specified in proposed TOP-003-3 from Project 2014-03.

Order No. 693 Citation	Directive/Guidance	Resolution
		Proposed TOP-010-1 **R5.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: **5.1.** Criteria for evaluating the quality of any analysis used in its Real-time Assessments; and **5.2.** Actions to resolve quality deficiencies in any analysis used in its Real-time Assessments. **R6.** Each Transmission Operator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. ***Proposed definition of Real-time Assessment (pending regulatory approval)*** 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.) ***Proposed TOP-001-3 (pending regulatory approval)*** **R13.** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
P 1875	...[w]e direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1	The directive was considered in developing the scope of Project 2009-02. NERC believes currently enforceable IRO standards,

Order No. 693 Citation	Directive/Guidance	Resolution
	to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.	proposed TOP and IRO standards, and currently-enforceable VAR standards address the directive as discussed below. Accordingly, additional requirements were not developed in Project 2009-02. RCs and TOPs are required to periodically perform Real-time Assessments consisting of an evaluation of system conditions "to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions." Entities must use whatever analysis is necessary to obtain an evaluation of system conditions, which may include real-time voltage stability analysis. Real-time Assessments assist operators in maintaining operations within established SOLs and IROLs, to include voltage stability criteria. Requirements for performing Real-time Assessments are contained in currently-enforceable IRO-008-1 and proposed IRO-008-2 and TOP-001-3 Reliability Standards as discussed above. VAR-001-1 was revised in Project 2013-04. The resulting standard, VAR-001-4, did not include an explicit requirement for periodic performance of voltage stability analysis because "such analysis would be performed pursuant to the SOL methodology developed under FAC standards."[1] VAR-001-4 requirement R1 specifies the TOP must establish a system voltage schedule as part of its plan to operate within SOLs and IROLs. ***Currently-enforceable VAR-001-4*** **R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an

[1] Reliability Standard VAR-001-4.1, Guidelines and Technical Basis section, page 13. Available at: http://www.nerc.com/pa/Stand/Reliability%20Standards/VAR-001-4.1.pdf

Order No. 693 Citation	Directive/Guidance	Resolution
		associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. **1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Requested Approvals

- IRO-018-1 - Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
- TOP-010-1 - Real-time Reliability Monitoring and Analysis Capabilities

Requested Retirements

- None

Prerequisite Approval

- TOP-003-3 Operational Reliability Data

Proposed TOP-010-1 contains requirements addressing the quality of data necessary for Transmission Operators and Balancing Authorities to perform Real-time monitoring and analysis functions. Requirements for specifying and providing this data appear in TOP-003-3. Accordingly, proposed TOP-010-1 cannot become effective prior to TOP-003-3.

Revisions to Defined Terms in the NERC Glossary

None

Applicable Entities

- Reliability Coordinators
- Transmission Operators
- Balancing Authorities

Effective Date

IRO-018-1

- Requirements R1, R2, and R5 shall become effective on the first day of the first calendar quarter that is 12 months after the date that this 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, Requirements R1, R2, and R5 shall become effective on the first day of the first calendar quarter that is 12 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
- Requirements R3 and R4 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, Requirements R3 and R4 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

TOP-010-1

If the prerequisite approval occurs on or before approval of the standards in Project 2009-02:

- Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date that this 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, Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
- Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this 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, Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date that this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

If the prerequisite approval occurs after approval of the standards in Project 2009-02:

- Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date that TOP-003-3 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, Requirements R1, R2, R3, R4, and R7 shall become effective on the first day of the first calendar quarter that is 12 months after the date TOP-010-1 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
- Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date that TOP-003-3 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, Requirements R5 and R6 shall become effective on the first day of the first calendar quarter that is 18 months after the date TOP-010-1 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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 is the first posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2015
45-day formal comment period with additional ballot	December 2015
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

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:** **Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **IRO-018-1**
3. **Purpose:** **Establish requirements for Real-time monitoring and analysis capabilities used by Reliability Coordinator System Operators in support of reliable System operations.**
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: The Reliability Coordinator (RC) uses a set of Real-time data identified in approved standard IRO-010-1a Requirement R1 and proposed standard 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 standards.

Requirement R1 Part 1.2 of this standard specifies the RC shall include actions to coordinate resolution of data quality discrepancies in its Operating Process or Operating Procedure. These actions could be the same as the process to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2, provided that this process could resolve Real-time data quality issues.

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] [Time Horizon: Same Day Operations, Real-time Operations]*

- **1.1.** Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to:
  - **1.1.1.** Data outside of a prescribed data range;
  - **1.1.2.** Analog data not updated within a predetermined time period;
  - **1.1.3.** Data entered manually to override telemetered information; and

1.1.4. Data otherwise identified as invalid or suspect.

1.2. Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data.

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 Procedure or Operating Process in electronic or hard copy format meeting all provisions of Requirement R1, and 2) evidence the Reliability Coordinator implemented the Operating Procedure or Operating Process as called for in the Operating Procedure or Operating Process, such as dated operator or supporting logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R2. Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Reliability Coordinator shall have evidence it provided its System Operators with indications of 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, computer printouts, system specifications, or other evidence.

Rationale for Requirements R3 and R4: Requirements R3 and R4 ensure the RC's System Operators have procedures and receive indication(s) to address issues related to the quality of the analysis inputs used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards.

R3. Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

3.1. Criteria for evaluating the quality of any analysis used in its Real-time Assessments; and

3.2. Actions to resolve quality deficiencies in any analysis used in its Real-time Assessments.

M3. Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Procedure or Operating Process in electronic or hard copy format meeting all provisions of Requirement R3, and 2) evidence the Reliability Coordinator implemented the Operating Procedure or Operating Process as called for in the

Operating Procedure or Operating Process, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R4. Each Reliability Coordinator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Reliability Coordinator shall have evidence it provided its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

Rationale for Requirement R5: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An independent alarm process monitor is one that would not fail with a simultaneous failure of the alarm processor. A 'heartbeat' or 'watchdog' monitoring system may accomplish this objective.

R5. Each Reliability Coordinator shall utilize an independent 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: Same Day Operations, Real-time Operations]*

M5. Each Reliability Coordinator shall have evidence it utilized an independent alarm process monitor that provided notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor 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, R2, and R5 and Measures M1, M2, and M5 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 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 Requirements R3 and R4 and Measures M3 and M4 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	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 and Part 1.2.	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 and Part 1.2; 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	N/A	N/A	The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of Real-time

				data used to perform its Real-time monitoring and Real-time Assessments.
R3.	N/A	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 and Part 3.2.	The Reliability Coordinator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 and Part 3.2; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments.
R4.	N/A	N/A	N/A	The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.
R5.	N/A	N/A	N/A	The Reliability Coordinator did not utilize an independent 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

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

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 existing and proposed TOP and IRO standards. As used in TOP and IRO standards, monitoring involves observing operating status and operating value(s) in Real-time for awareness of system conditions. Real-time monitoring includes 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.

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.

A. Introduction

1. **Title:** Reliability Coordinator Data Specification and Collection
2. **Number:** IRO-010-2
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability**
   - **4.1.** Reliability Coordinator.
   - **4.2.** Balancing Authority.
   - **4.3.** Generator Owner.
   - **4.4.** Generator Operator.
   - **4.5.** Load-Serving Entity.
   - **4.6.** Transmission Operator.
   - **4.7.** Transmission Owner.
   - **4.8.** Distribution Provider.
5. **Proposed Effective Date:**

   See Implementation Plan.
6. **Background**

   See Project 2014-03 project page.

B. Requirements

R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

- **1.1.** A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
- **1.2.** Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability.
- **1.3.** A periodicity for providing data.
- **1.4.** The deadline by which the respondent is to provide the indicated data.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification for data.

R2. The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

3.1 A mutually agreeable format

3.2 A mutually agreeable process for resolving data conflicts

3.3 A mutually agreeable security protocol

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

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 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. Data Retention

The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 dated, current, in force documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.

The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.

Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R1	Operations Planning	Low	The Reliability Coordinator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
						monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R2	Operations Planning	Low	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time	The Reliability Coordinator did not distribute its data specification as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
				Assessments.	monitoring, and Real-time Assessments.	Assessments.
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow one of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow two of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 satisfied the obligations of the documented specifications for data but failed to follow any of the criteria shown in Parts 3.1 – 3.3.	The responsible entity receiving a data specification in Requirement R2 did not satisfy the obligations of the documented specifications for data.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03

Guidelines and Technical Basis

Rationale:

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

Rationale for Definitions:
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 Applicability Changes:

Changes were made to applicability based on IRO FYRT recommendation to address the need for UVLS and UFLS information in the data specification.

The Interchange Authority was removed because activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities. The Balancing Authority is the responsible functional entity for these tasks.

The Planning Coordinator and Transmission Planner were removed from Draft 2 as those entities would not be involved in a data specification concept as outlined in this standard.

Rationale:

Proposed Requirement R1, Part 1.1:
Is in response to issues raised in NOPR paragraph 67 on the need for obtaining non-BES and external network data necessary for the Reliability Coordinator to fulfill its responsibilities.

Proposed Requirement R1, Part 1.2:
Is in response to NOPR paragraph 78 on relay data.

Proposed Requirement R3, Part 3.3:

Is in response to NOPR paragraph 92 where concerns were raised about data exchange through secured networks.

Corresponding changes have been made to proposed TOP-003-3.

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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):	Project 2009-02: Real-time Reliability Monitoring and Analysis Capabilities		
Date Submitted:	June 18, 2015		
SAR Requester Information			
Name:	Saad Malik		
Organization:	Peak Reliability		
Telephone:	970.776.5635	E-mail:	smalik@peakrc.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.):
To establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations.
Industry Need (What is the industry problem this request is trying to solve?):
According to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* dated April 2004 (2003 Blackout Report), a principal cause of the August 14 blackout was a lack of situational awareness. Recommendation 22 of the 2003 Blackout Report states that the industry should "evaluate and adopt better Real-time tools for operators and reliability coordinators." NERC's Operating Committee formed the Real-time Tools Best Practices Task Force (RTBPTF) to evaluate Real-time tools and their usage within the industry. The Task Force produced the report *Real-Time Tools Survey Analysis and Recommendations* dated March 13, 2008 (RTBPTF Report)

SAR Information
that included recommendations for the functionality, performance, and management of Real-time tools. The FERC and NERC Staff Report *Arizona-Southern California Outages on September 8, 2011* (2011 Southwest Outage Report) also cited weaknesses in Real-time situational awareness and recommended improvements in Real-time monitoring and analysis capabilities. In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to System operators: • P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.* • P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.* • P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.* This SAR addresses the event reports, Order No. 693 directives, and recommendations from the RTBPTF Report that have not been addressed in other standards projects. The SAR Drafting Team also conducted a Technical Conference on June 4, 2015 to obtain stakeholder input on reliability objectives to be addressed in the proposed project.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standards Drafting Team (SDT) shall develop requirements and definition(s), as needed, for Real-time monitoring and analysis capabilities to ensure effective operator situational awareness. The project will address recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.
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.)
Situational awareness of Real-time system operations is enabled through monitoring and analysis tasks performed by operators. Existing and proposed TOP and IRO standards and definitions developed in

SAR Information
Project 2014-03 Revisions to TOP and IRO Standards require Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed project will provide additional reliability benefits by addressing issues with the availability and information quality of Real-time monitoring and analysis capabilities. Specifically, the SDT will develop requirements and definition(s), as needed, to accomplish the following: • Establish a common understanding of *monitoring* as it applies to Real-time situational awareness of the Bulk Electric System (BES), • Provide operators with indication(s) of the quality of information being provided by *monitoring* capabilities and procedure(s) to address data quality issues, • Provide operators with notification(s) during unplanned loss of *monitoring* capabilities, and • Provide operators with indication(s) of the quality of information being provided by *analysis* capabilities and procedure(s) to address analysis quality issues. When completed, the project will have addressed recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.

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

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

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.

Reliability and Market Interface Principles	
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Related Standards	
Standard No.	Explanation
Project 2014-03 Revisions to TOP and IRO Standards	Proposed TOP and IRO standards and definitions from Project 2014-03 require RC, TOP, and BAs to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed standards and definitions are pending regulatory approval.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

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Standards Authorization Request Form

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Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Project 2009-02: Real-time Reliability Monitoring and Analysis Capabilities		
Date Submitted:	June 18, 2015		
SAR Requester Information			
Name:	Saad Malik		
Organization:	Peak Reliability		
Telephone:	970.776.5635	E-mail:	smalik@peakrc.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.):
To establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of reliable System operations.
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SAR Information
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Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standards Drafting Team (SDT) shall develop requirements and definition(s), as needed, for Real-time monitoring and analysis capabilities to ensure effective operator situational awareness. The project will address recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.
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.)
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SAR Information
Project 2014-03 Revisions to TOP and IRO Standards require Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed project will provide additional reliability benefits by addressing issues with the availability and information quality of Real-time monitoring and analysis capabilities. Specifically, the SDT will develop requirements and definition(s), as needed, to accomplish the following: • Establish a common understanding of *monitoring* as it applies to Real-time situational awareness of the Bulk Electric System (BES), • Provide operators with indication(s) of the quality of information being provided by *monitoring* capabilities and procedure(s) to address data quality issues, • Provide operators with notification(s) during unplanned loss of *monitoring* capabilities, • Provide operators with indication(s) of the quality of information being provided by *analysis*, and capabilities and procedure(s) to address analysis quality issues~~., and~~ ~~• Provide operators with notification(s) during unplanned loss of *analysis* capabilities.~~ When completed, the project will have addressed recommendations from the 2003 Blackout Report, the 2011 Southwest Outage Report, and the RTBPTF Report, as well as directives from FERC Order No. 693, that have not already been addressed in existing or proposed Reliability Standards.

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.
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☐	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
Project 2014-03 Revisions to TOP and IRO Standards	Proposed TOP and IRO standards and definitions from Project 2014-03 require RC, TOP, and BAs to perform monitoring and analysis to prevent instability, uncontrolled separation, and Cascading outages that adversely impact the Interconnection. The proposed standards and definitions are pending regulatory approval.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Justification

Project 2009-02 Real-time Monitoring and Analysis Capabilities

RELIABILITY | ACCOUNTABILITY






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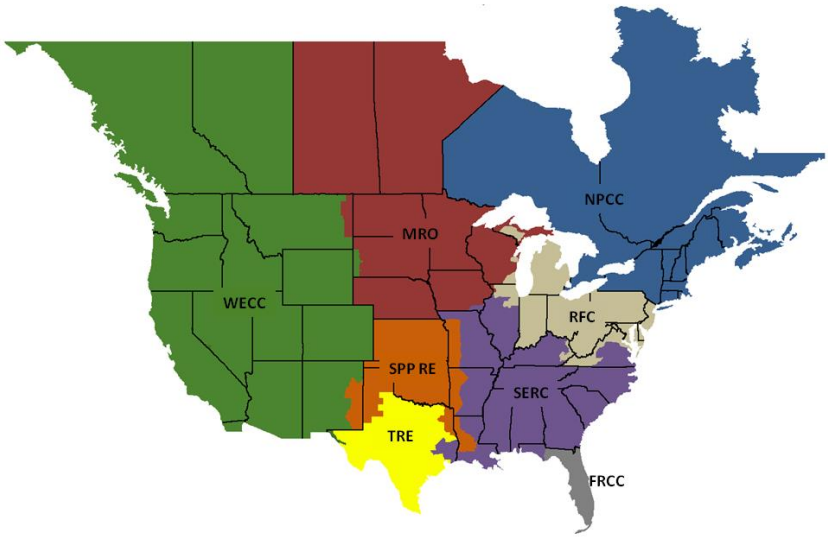
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to 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

In April 2015, the Standards Committee appointed a new Standards Authorization Request (SAR) Drafting Team (SAR DT) for Project 2009-02 Real-time Monitoring and Analysis Capabilities. This project originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). Several new Reliability Standards and defined terms have been approved or filed for approval in the years since Project 2009-02 was initiated, including the standards developed in Project 2014-03 Revisions to TOP and IRO Standards. As a result, many of the original issues identified by the RTBPTF for Project 2009-02 have been addressed. In addition, relevant observations and recommendations have emerged from more recent events on the Bulk Electric System (BES) and operating practices have evolved over time. The SAR DT has reviewed previous work done in Project 2009-02, new standards and defined terms, relevant industry report findings and recommendations including those contained in the 2011 Southwest Outage report, and industry observations and practices relevant to real-time situational awareness to assist in developing a comprehensive SAR.

This white paper describes the SAR DT's approach to developing the SAR and discusses the technical basis for developing Reliability Standards in Project 2009-02. This white paper and the associated SAR together are intended to fully describe the project purpose, industry need, and project scope.

Chapter 1 – Background

FERC Order No. 693[1] highlights the need for a minimum set of capabilities to be available to assist operators in making real-time decisions. The work done by the RTBPTF, which was formed by NERC in response to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, became the basis for the Real-time Monitoring and Analysis Capabilities (RTMAC) standards development project when it was initiated in 2009. Although Reliability Standards affecting the operating reliability of the Bulk Electric System (BES) have improved significantly over the years since first becoming mandatory in 2007, a reliability issue has persisted in the area of real-time situational awareness capabilities as highlighted in BES event reports and an independent review of the NERC Reliability Standards. A review of industry reports and recommendations pertaining to real-time monitoring and analysis capabilities is provided in this document and in the Appendix. These recommendations, along with the FERC Order No. 693 directives, describe the industry need for the current RTMAC standards project.

BES Event Reports

Project 2009-02, like some other Reliability Standards projects, is informed by the lessons learned from past outages. The two significant outages discussed below highlight issues in real-time situational awareness, among other reliability concerns. Many Communications (COM), Transmission Operations (TOP), and Interconnection Reliability Operations (IRO) standards have addressed event report recommendations to improve the way the BES is planned and operated. The scope of Project 2009-02 is intended to include remaining recommendations from the 2003 Blackout Report and the 2011 Southwest Outage Report that pertain to real-time monitoring and analysis capabilities.

2003 Blackout Report

The largest blackout in history to affect North America began on the afternoon of August 14, 2003 and disrupted over 61,800 Megawatts of electric load in the Northeastern U.S. and the Canadian province of Ontario. Severe impacts to electrical service lasted for nearly one week and an estimated 50 million people were affected. A comprehensive investigation conducted by U.S. and Canadian government and industry leaders identified a host of principal and contributing causes, including:

- Failure to maintain adequate reactive power support,
- Failure to ensure operation within secure limits,
- Inadequate vegetation management,
- Inadequate operator training,
- Failure to identify emergency conditions and communicate that status to neighboring systems, and
- Inadequate regional-scale visibility over the Bulk-Power System (BPS).

Among other causes, the 2003 blackout was linked to dysfunction of SCADA/EMS systems. Additionally, investigators pointed out that several deficiencies leading to the 2003 blackout were also identified weaknesses in previous outages, indicating the need for more effective response. Previous post-event reports included recommendations aimed at improving capabilities for visualizing changes to facilities within the system, and for visualizing changes to facilities in neighboring systems that could have a potential impact. A recurring recommendation also focused on providing capabilities for operators to evaluate courses of action. These

[1] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, 72 Fed. Reg. 16416 at P 1660 (Apr. 4, 2007), FERC Stats. And Regs.¶ 31,242, *order on reh'g,* Order No. 693-A, 120 FERC ¶ 61,053 (2007) (Order No. 693).

observations led to the recommendation in the final report of the 2003 blackout for NERC to **evaluate and adopt better real-time tools for operators and reliability coordinators.**[2]

In response, the NERC Operating Committee organized the RTBPTF to study the real-time situational awareness practices in use within the electric power industry and make recommendations concerning the establishment of minimum capabilities necessary for reliable operations. The RTBPTF report *Real-time Tools Survey Analysis and Recommendations,*[3] completed in 2008*,* is the result of extensive information gathering and analysis and includes recommendations for new or enhanced Reliability Standards, operating guides, and areas for further analysis. This report became a basis for initiating the Real-time Monitoring and Analysis Capabilities project in 2009.

Although exhaustive and comprehensive, some of the RTBPTF recommendations go beyond the scope of situational awareness monitoring and capabilities. In addition, many other recommendations have been addressed in other subsequent standards projects. The appendix provides a description of RTBPTF report recommendations and the SAR DT's determination of applicability within the scope of Project 2009-02.

An early Concept White Paper describing potential performance, availability, quality, and maintenance parameters based on the RTBPTF Report was developed in 2011. The SAR DT reviewed the white paper and confirmed that, due to significant changes to Reliability Standards and operating practices since it was drafted, the 2011 Concept White Paper is no longer relevant to the current effort in Project 2009-02.

2011 Southwest Outage Report

Like the 2003 blackout in the northeast, the blackout that occurred in the southwest in September 2011 was partly due to, or exacerbated by, inadequate real-time situational awareness. On the afternoon of September 8, 2011, the loss of a single 500 kV line led to widespread cascading outages affecting 2.7 million customers in Arizona, Southern California, and Baja, Mexico. Inadequate operations planning was a significant factor in the failure to maintain a secure N-1 state. However, the report also highlighted several concerns with entities and their ability to monitor, identify, and plan for the next most critical contingency in real-time.[4]

Project 2014-03 - Revisions to TOP and IRO Standards addressed many of the recommendations contained in the 2011 Southwest Outage Report related to operations planning and real-time situational awareness. A complete description is provided in the Southwest Outage Report mapping document for Project 2014-03.[5] Revised definitions and performance requirements for Real-time Assessments and Operational Planning Analysis and proposed requirements for developing and implementing Operating Plans to prevent and mitigate operating limit exceedances address most of the real-time situational awareness recommendations from the report. However some recommendations contain aspects pertaining to real-time capabilities that should be considered in Project 2009-02, as described in the appendix. Accordingly, Project 2009-02 will develop requirements to address remaining recommendations as described in the following chapter.

[2] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* Recommendation 22*,* available at http://www.nerc.com/pa/rrm/ea/2003%20Blackout%20Final%20Report/Forms/AllItems.aspx.

[3] *Real-Time Tools Survey Analysis and Recommendations* (March 13, 2008), available at http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf.

[4] *Arizona-Southern California Outages on September 8, 2011* (April 2012), available at http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

[5] See the project page for 2014-03, available at http://www.nerc.com/pa/stand/pages/project-2014-03-revisions-to-top-and-iro-standards.aspx.

FERC Directives

In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to operators.[6] FERC indicated that the intent of the directive is to ensure operating entities have adequate tools to perform their real-time reliability functions.[7]

- P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.*
- P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.*
- P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.*

Independent Experts Review Project (IERP) Report

In 2013, NERC retained a team of five industry experts to assess the quality of the enforceable body of standards and make recommendations for improvements that could be implemented by NERC and the industry.[8] Among the recommendations made by the panel of experts was the identification of potential risks to reliability that may not be adequately addressed in Reliability Standards. The report recommended resuming development of the Real-time Monitoring and Analysis Capabilities standards project.

Proposed TOP and IRO Standards

Since Project 2009-02 was initiated in 2009, many standards and definitions have been revised or developed that address real-time situational awareness issues. In particular, the revised TOP and IRO standards in Project 2014-03, which are pending regulatory approval, include key provisions for real-time situational awareness and operations planning. In reviewing the RTBPTF report recommendations for applicability in the current Project 2009-02 effort, the SAR DT considered the Project 2014-03 standards as noted in the Appendix.

The proposed TOP and IRO standards in Project 2014-03 provide requirements for performing monitoring and analysis through the definition of Real-time Assessment, Operational Planning Analysis, and the relevant requirements. Accordingly, additional requirements to perform monitoring or analysis will not be included in the scope for Project 2009-02. Furthermore, requirements for data exchange to support real-time monitoring and analysis will not be included in scope for Project 2009-02 because they are addressed through data specification requirements in IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3.

---

[6] Order No. 693 at P 905 (approving IRO-002-1 and directing modifications) and P 1665 (approving TOP-006-1 and directing modifications.

[7] Additionally, in approving VAR-001-1 - Voltage and Reactive Control, the Commission directed NERC to develop modifications to the standard to require periodic performance of voltage stability analysis to assist in real-time operations. The commission clarified that this could be accomplished through online tools where available, or offline simulation tools.

- §1875: *...[w]e direct the ERO, through its Reliability Standards development process, ...to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.*

VAR-001 was revised in the Project 2013-04, however the revised standard did not include a requirement for periodic performance of voltage stability analysis because voltage stability analysis is performed per SOL Methodology developed under FAC standards.

[8] See The Standards Independent Experts Review Project report. Available at www.nerc.com /pa/Stand/_layouts/xlviewer.aspx?id=/pa/Stand/Documents/P81_and%20IERP_Recommendations_for_Retirement_010815.xlsx.

Technical Conference

NERC and the SAR DT held a Technical Conference in Atlanta on June 4, 2015, to obtain industry input on reliability issues to be addressed in the proposed project. Participant subject matter experts representing a diverse mix of regional and functional entities shared their perspectives on the use of real-time situational awareness capabilities for reliable operations. There was consensus that many RTBPTF recommendations have been addressed in current or proposed TOP and IRO standards. However, Technical Conference participants agreed that issues identified by the RTBPTF pertaining to availability and information quality of real-time monitoring and analysis capabilities were still relevant.

Chapter 2 – Project Scope

The SAR DT has reviewed all recommendations from the RTBPTF and relevant recommendations from event reports, along with the existing body of standards, to identify remaining issues that should be in the scope for Project 2009-02. Table 1 below shows the resulting recommendations to be addressed. Additionally, the project will address outstanding FERC directives discussed in the preceding chapter.

Table 1: Report Recommendations to Address in Project 2009-02

Source	Recommendation	Discussion	Applicable Entity
2003 Blackout Report	Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators.	Project 2009-02 will develop requirements for real-time reliability monitoring and analysis capabilities to address issues not already addressed in other Reliability Standards. RTBPTF report recommendations will be considered in development.	RC, TOP, BA
2011 Southwest Outage Report	Recommendation 12 - [entities] should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2009-02 will develop requirements to improve the adequacy and operation of real-time monitoring and analysis capabilities. Requirements addressing the frequency that real-time tools run are contained in other standards and are not in the scope of this project.	RC, TOP, BA
RTBPTF Report	S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • Alarm Tools • Telemetry Data Systems • Network Topology Processor • State Estimator • Contingency Analysis	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. Prescription of specific tools is not in scope. Project approach is discussed below.	RC, TOP, BA as discussed below
RTBPTF Report	S7 - S8, S11-S12, S40 - Availability of various monitoring and analysis capability processes	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring capabilities are not available (i.e., not performing their intended function).	RC, TOP, BA

Project Purpose and Approach

Project 2009-02 will develop requirements for real-time monitoring and analysis capabilities used by operators in support of reliable System operations. Functional requirements for performing *monitoring* and *analysis* tasks are well established in Reliability Standards as discussed throughout this white paper. However, reliability could be improved by:

- Developing a common understanding of *monitoring* as it applies to real-time situational awareness of the BES,
- Providing operators with indication(s) of the quality of information being provided by *monitoring* and *analysis* capabilities, and
- Providing operators with notification(s) during unplanned loss of *monitoring* capabilities.

Project 2009-02 will develop requirements and definition(s), as needed, to accomplish these reliability objectives as discussed.

Real-time Situational Awareness Concept

From the RTBPTF Report:

> *Situational awareness, as RTBPTF understands it, means ensuring that accurate information on current system conditions, including the likely effects of future contingencies, is continuously available in a form that allows operators to quickly grasp and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.*

The Project 2009-02 SAR DT believes that situational awareness encompasses two broad capabilities: monitoring and analysis. To be effective in supporting real-time situational awareness, monitoring and analysis must:

- Be performed with sufficient frequency to allow operators to understand operating conditions and take corrective actions when necessary,
- Provide awareness of information quality to allow operators to assess the accuracy of information being received on system conditions and take corrective actions when necessary, and
- Indicate when monitoring or analysis processes are not operating normally or are unavailable in order to provide operator awareness of the accuracy of the information being provided.

Project 2009-02 will develop new requirements and definition(s), as needed, that support this concept of situational awareness without duplicating aspects that are already addressed in the existing and proposed body of Reliability Standards. As discussed in the preceding chapter, requirements for the Reliability Coordinator (RC), Transmission Operator (TOP), and Balancing Authority (BA) to perform monitoring and analysis are covered under existing and proposed TOP and IRO standards. Therefore, Project 2009-02 will focus on developing requirements to address information quality and operator awareness of real-time monitoring and analysis capabilities. Table 2 shows reliability objectives that should be addressed in requirements for this project.

Monitoring

Monitoring BES facilities in real-time is a primary function of the RCs, TOPs, and BAs and is addressed in existing and proposed TOP and IRO standards. For RCs, proposed IRO-002-4 states:

> *R3. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.*

For TOPs and BAs, proposed TOP-001-3 states:

> *R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:*
>
> *10.1. Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and*
>
> *10.2. Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.*
>
> *R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.*

The SAR DT understands *monitoring* capabilities may include both alarming and information visualization. Project 2009-02 will aim to develop a consistent understanding of *monitoring* within the industry. The project will also address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of information being provided by a monitoring system, and indication when a monitoring system is not operating normally.

Analysis

The *analysis* component of the Real-time situational awareness concept is described by the definition of Real-time Assessment, which is pending FERC approval along with the proposed TOP and IRO standards. The proposed definition is as follows:

> ***Real-time Assessment*** *- An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)*

Requirements for performing Real-time Assessments are contained in proposed IRO-008-2 and TOP-001-3:

> ***Proposed IRO-008-2***
> *R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.*
>
> ***Proposed TOP-001-3***
> *R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.*

The SAR DT believes the proposed definition of Real-time Assessment and the requirements in proposed IRO-008-2 and TOP-001-3 provide RCs and TOPs with flexibility to determine which real-time tools, such as State Estimator, Contingency Analysis, and Stability Applications, are necessary to meet their real-time reliability functions. Consequently, prescriptive requirements for real-time tools are not in scope for Project 2009-02.

The project will address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of the analysis used in Real-time Assessments.

Table 2: Project 2009-02 Reliability Objectives

	Monitoring Capabilities	Analysis Capabilities
Quality	Provide operator with indication of information quality and procedures to address data quality issues.	Provide operator with indication of information quality and procedures to address analysis quality issues.
Availability	Provide operator with notification any time monitoring system is not operating normally.	N/A

Appendix – Report Recommendations

The table below contains recommendations for improved real-time situational awareness capabilities found in relevant industry reports and how these recommendations have been addressed, if applicable. If recommendations have not been addressed fully, the table includes a description of how they should be addressed in Project 2009-02. The following industry reports are considered here[9]:

- 2003 Blackout Final Report
- 2011 Southwest Outage Report
- Real-time Tools Best Practices Task Force

Report Recommendation Mapping	
Report Recommendation	**Applicable Standard(s)**
2003 Blackout Final Report	
Recommendation 1-21, 23-46	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators. Operating Committee to evaluate the real-time operating tools necessary for reliability operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices.	The Operating Committee established the RTBPTF to evaluate real-time operating tools and make recommendations for proposed standards. Project 2009-02 should consider these recommendations as discussed below.
2011 Southwest Outage Report	
Recommendation 1-10, 13-26	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 11 - TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Project 2014-03 developed the proposed definition of Real-time Assessment and proposed TOP-003-3 Requirement R1 which describes the requirements for a data specification that will provide all of the data that a TOP needs in order to fulfill its reliability function. Together, these address capabilities and required data TOPs must have to ensure adequate situational awareness. **Real-time Assessment -** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-003-3, Requirement R1, Part 1.1**:

[9] *All industry reports are available on the 2009-02 Project Page: http://www.nerc.com/pa/Stand/Pages/Project-2009-02-Real-time-Reliability-Monitoring-and-Analysis-Capabilities.aspx.*

	A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.
Recommendation 12 - TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2014-03 developed a requirement for the performance of a Real-time Assessment for Transmission Operators. Standards developed in Project 2009-02 will address the adequacy of tools as described in this recommendation. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
Recommendation 27 - TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences.	Proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA) developed in Project 2014-03 specify that identified phase angle limitations must be considered and deal with applying phase angle information. Proposed TOP-002 Requirement R2 specifies that TOPs must have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified in the OPA. Data specification requirements in approved IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3 provide a means for RCs and TOPs to obtain phase angle information. **Proposed Definition: Operational Planning Analysis:** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment:** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System

	Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
RTBPTF Report	
S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • **Alarm Tools** • **Telemetry Data Systems** • **Network Topology Processor** • **State Estimator** • **Contingency Analysis**	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. However, prescription of specific tools is not in scope.
S2 - Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.	Not in scope. Reliability objective is accomplished through monitoring and analysis requirements as discussed below.
S3 - Add new requirements and measures pertaining to RC monitoring of the bulk electric system.	Addressed in IRO standards (current and proposed). **IRO-002-2** R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. **IRO-003-2** R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. **Proposed IRO-002-4** R3. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
S4 - Develop data-exchange standards.	Addressed in proposed TOP-001-3 and IRO-002-4. **Proposed TOP-001-3** R19. Each Transmission Operator shall have 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. R20. Each Balancing Authority shall have 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. **Proposed IRO-002-4** 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.
S5 - Develop data-availability standards and a process for trouble resolution and escalation.	Data availability and trouble resolution is addressed in IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. ... **Proposed IRO-010-2** R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
S6 - Develop a new weather data requirement related to situational awareness and real-time operational capabilities.	EOP-010-1 covers space weather dissemination. The SAR DT views monitoring other weather information as common utility practice that does not require a reliability standard.
S7 - Specify and measure minimum availability for alarm tools.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the

	RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function). Availability notification for analysis tools is addressed in IRO-008-1, and proposed IRO-008-2 proposed TOP-001-3 from Project 2014-30. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed IRO-008-2** R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
S8 - Specify and measure minimum availability for network topology processor.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S9 - Establish a uniform formal process to determine the "wide area view boundary" and show boundary data/results.	Wide-area is now a defined term. Recommendation has been addressed.
S10 - Develop compliance measures for verification of the usage of "wide-area overview display" visualization tools.	IRO standards revisions have addressed compliance measures.
S11 - Specify and measure minimum availability for state estimator, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S12 - Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation to provide operator awareness when key monitoring and alarming tools are not available (i.e. not performing their intended function).
S13 - Specify criteria and develop measures for defining contingencies.	Not in scope; Addressed in approved TPL and FAC standards.
S14 - Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.	Requirements for assessing pre- and post-contingency system conditions are addressed in Real-time Assessment (RTA) and Operational Planning Analysis (OPA) definitions. Requirements for performing RTA and OPA are contained in

	proposed TOP-001-3, TOP-002-4, IRO-008-2, and approved IRO-008-1. **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed definition** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations.

	(Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
S15 - Provide real-time awareness of load-shed capability to address potential or actual IROL violations.	Addressed in proposed EOP-011-1, approved IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

	2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. ... **Proposed IRO-010-2** R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time

	monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
S16 - Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.	BA responsibilities for managing Contingency Reserve are addressed in the approved BAL-002-1 standard which is under revision in Project 2010-014. 1. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.
S17 - Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves.	Addressed in VAR-001-4, BAL-002, and proposed IRO-002-4 and TOP-001-3. **VAR-001-4** R4. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. **Proposed IRO-002-4** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3** R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
S18 - Establish document plans and procedures for conservative operations.	Addressed in proposed EOP-011-1 Requirement R1. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating

	Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

S19 - Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.	Addressed in proposed TOP-001-3, and IRO-008-2 and the proposed definitions for Operational Planning Analysis and Real-time Assessment. **Proposed TOP-001-3** 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. R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. R14. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-008-2** R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. R5. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed definition** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be

	provided through internal systems or through third-party services.)
S20 - Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.
S21 - Review and update operating guides (mitigation plans) **when day-ahead or current day studies indicate the potential need to implement an operating guide.**	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for

	the next-day provided by its Transmission Operators and Balancing Authorities.
S22 - Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.
S23 - Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions.	Addressed in IRO-014-2, proposed IRO-014-3 and proposed IRO-008-2. **IRO-014-2** R1. Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall collectively address the following: ... **Proposed IRO-014-3** R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: ... **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as

	a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.
S24 - Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S25 - Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S26 - Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.	Not in scope. This is administrative in nature.
S27 - State the specific purpose of existence for each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S28 - Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S29 - Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S30 - Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.	Not in scope. This is administrative in nature.
S31 - Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.	Not in scope. Recommendation is appropriate as a guideline rather than a reliability standard.
S32 - Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.	Not in scope. This is administrative in nature.
S33 - Provide the location, real-time status, and MWs of load available to be shed.	Addressed in proposed EOP-011-1 Requirement R1 Part 1.2.5 and proposed TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

	1.2.6. Reliability impacts of extreme weather conditions. **Proposed TOP-003-3** R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. ...
S34 - Establish documented procedures for the reassessment and re-posturing of the system following an event.	Addressed in proposed TOP-002-4 and IRO-008-2, and approved EOP-005-2 and EOP-006-2. **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ...

	EOP-006-2 R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S35 - Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.	Addressed in approved IRO-010-1, proposed TOP-003-3, proposed IRO-010-2, approved EOP-005-2, and approved EOP-006-2. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... R1.6. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. ... **Proposed TOP-003-3** R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. ... **Proposed IRO-010-2** R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses,

	Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ... R1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit. ... R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **EOP-006-2** R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S36 - Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.	Addressed in approved EOP-005-2 and proposed IRO-017-1 - Outage Coordination. **EOP-005-2** R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **Proposed IRO-017-1** R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation

	and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: ...
S37 - Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.	Not in scope. This is administrative in nature.
S38 - Maintain event logs pertaining to critical equipment status for a period of one year.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be "installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools". Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S39 - Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be "installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools". Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S40 - Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and analysis capabilities are not available (i.e., not performing their intended function).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Justification

Project 2009-02 Real-time Monitoring and Analysis Capabilities

RELIABILITY | ACCOUNTABILITY






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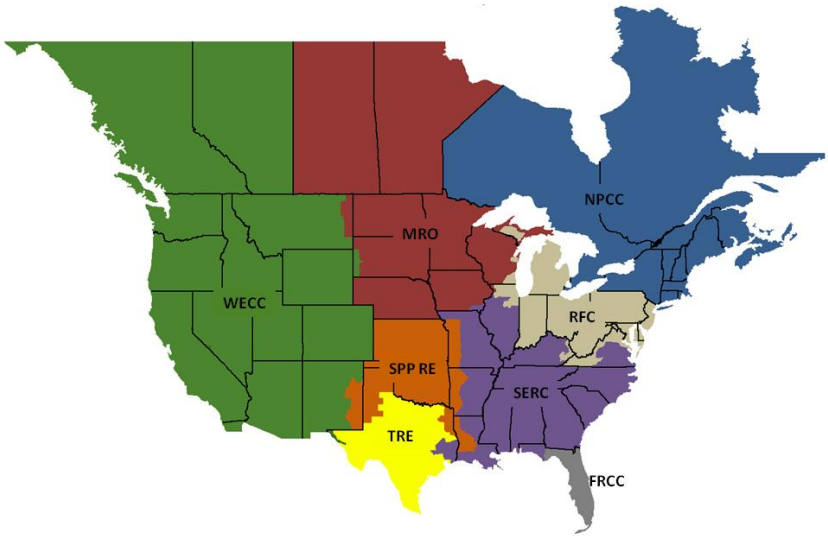
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to 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

In April 2015, the Standards Committee appointed a new Standards Authorization Request (SAR) Drafting Team (SAR DT) for Project 2009-02 Real-time Monitoring and Analysis Capabilities. This project originated in 2009 in response to work done by the NERC Operating Committee's Real-time Tools Best Practices Task Force (RTBPTF). Several new Reliability Standards and defined terms have been approved or filed for approval in the years since Project 2009-02 was initiated, including the standards developed in Project 2014-03 Revisions to TOP and IRO Standards. As a result, many of the original issues identified by the RTBPTF for Project 2009-02 have been addressed. In addition, relevant observations and recommendations have emerged from more recent events on the Bulk Electric System (BES) and operating practices have evolved over time. The SAR DT has reviewed previous work done in Project 2009-02, new standards and defined terms, relevant industry report findings and recommendations including those contained in the 2011 Southwest Outage report, and industry observations and practices relevant to real-time situational awareness to assist in developing a comprehensive SAR.

This white paper describes the SAR DT's approach to developing the SAR and discusses the technical basis for developing Reliability Standards in Project 2009-02. This white paper and the associated SAR together are intended to fully describe the project purpose, industry need, and project scope.

Chapter 1 – Background

FERC Order No. 693[1] highlights the need for a minimum set of capabilities to be available to assist operators in making real-time decisions. The work done by the RTBPTF, which was formed by NERC in response to the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, became the basis for the Real-time Monitoring and Analysis Capabilities (RTMAC) standards development project when it was initiated in 2009. Although Reliability Standards affecting the operating reliability of the Bulk Electric System (BES) have improved significantly over the years since first becoming mandatory in 2007, a reliability issue has persisted in the area of real-time situational awareness capabilities as highlighted in BES event reports and an independent review of the NERC Reliability Standards. A review of industry reports and recommendations pertaining to real-time monitoring and analysis capabilities is provided in this document and in the Appendix. These recommendations, along with the FERC Order No. 693 directives, describe the industry need for the current RTMAC standards project.

BES Event Reports

Project 2009-02, like some other Reliability Standards projects, is informed by the lessons learned from past outages. The two significant outages discussed below highlight issues in real-time situational awareness, among other reliability concerns. Many Communications (COM), Transmission Operations (TOP), and Interconnection Reliability Operations (IRO) standards have addressed event report recommendations to improve the way the BES is planned and operated. The scope of Project 2009-02 is intended to include remaining recommendations from the 2003 Blackout Report and the 2011 Southwest Outage Report that pertain to real-time monitoring and analysis capabilities.

2003 Blackout Report

The largest blackout in history to affect North America began on the afternoon of August 14, 2003 and disrupted over 61,800 Megawatts of electric load in the Northeastern U.S. and the Canadian province of Ontario. Severe impacts to electrical service lasted for nearly one week and an estimated 50 million people were affected. A comprehensive investigation conducted by U.S. and Canadian government and industry leaders identified a host of principal and contributing causes, including:

- Failure to maintain adequate reactive power support,
- Failure to ensure operation within secure limits,
- Inadequate vegetation management,
- Inadequate operator training,
- Failure to identify emergency conditions and communicate that status to neighboring systems, and
- Inadequate regional-scale visibility over the Bulk-Power System (BPS).

Among other causes, the 2003 blackout was linked to dysfunction of SCADA/EMS systems. Additionally, investigators pointed out that several deficiencies leading to the 2003 blackout were also identified weaknesses in previous outages, indicating the need for more effective response. Previous post-event reports included recommendations aimed at improving capabilities for visualizing changes to facilities within the system, and for visualizing changes to facilities in neighboring systems that could have a potential impact. A recurring recommendation also focused on providing capabilities for operators to evaluate courses of action. These

[1] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, 72 Fed. Reg. 16416 at P 1660 (Apr. 4, 2007), FERC Stats. And Regs.¶ 31,242, *order on reh'g,* Order No. 693-A, 120 FERC ¶ 61,053 (2007) (Order No. 693).

observations led to the recommendation in the final report of the 2003 blackout for NERC to **evaluate and adopt better real-time tools for operators and reliability coordinators.**[2]

In response, the NERC Operating Committee organized the RTBPTF to study the real-time situational awareness practices in use within the electric power industry and make recommendations concerning the establishment of minimum capabilities necessary for reliable operations. The RTBPTF report *Real-time Tools Survey Analysis and Recommendations,*[3] completed in 2008*,* is the result of extensive information gathering and analysis and includes recommendations for new or enhanced Reliability Standards, operating guides, and areas for further analysis. This report became a basis for initiating the Real-time Monitoring and Analysis Capabilities project in 2009.

Although exhaustive and comprehensive, some of the RTBPTF recommendations go beyond the scope of situational awareness monitoring and capabilities. In addition, many other recommendations have been addressed in other subsequent standards projects. The appendix provides a description of RTBPTF report recommendations and the SAR DT's determination of applicability within the scope of Project 2009-02.

An early Concept White Paper describing potential performance, availability, quality, and maintenance parameters based on the RTBPTF Report was developed in 2011. The SAR DT reviewed the white paper and confirmed that, due to significant changes to Reliability Standards and operating practices since it was drafted, the 2011 Concept White Paper is no longer relevant to the current effort in Project 2009-02.

2011 Southwest Outage Report

Like the 2003 blackout in the northeast, the blackout that occurred in the southwest in September 2011 was partly due to, or exacerbated by, inadequate real-time situational awareness. On the afternoon of September 8, 2011, the loss of a single 500 kV line led to widespread cascading outages affecting 2.7 million customers in Arizona, Southern California, and Baja, Mexico. Inadequate operations planning was a significant factor in the failure to maintain a secure N-1 state. However, the report also highlighted several concerns with entities and their ability to monitor, identify, and plan for the next most critical contingency in real-time.[4]

Project 2014-03 - Revisions to TOP and IRO Standards addressed many of the recommendations contained in the 2011 Southwest Outage Report related to operations planning and real-time situational awareness. A complete description is provided in the Southwest Outage Report mapping document for Project 2014-03.[5] Revised definitions and performance requirements for Real-time Assessments and Operational Planning Analysis and proposed requirements for developing and implementing Operating Plans to prevent and mitigate operating limit exceedances address most of the real-time situational awareness recommendations from the report. However some recommendations contain aspects pertaining to real-time capabilities that should be considered in Project 2009-02, as described in the appendix. Accordingly, Project 2009-02 will develop requirements to address remaining recommendations as described in the following chapter.

[2] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* Recommendation 22*,* available at http://www.nerc.com/pa/rrm/ea/2003%20Blackout%20Final%20Report/Forms/AllItems.aspx.

[3] *Real-Time Tools Survey Analysis and Recommendations* (March 13, 2008), available at http://www.nerc.com/comm/OC/Realtime%20Tools%20Best%20Practices%20Task%20Force%20RTBPTF%2020/Real-Time%20Tools%20Survey%20Analysis%20and%20Recommendations.pdf.

[4] *Arizona-Southern California Outages on September 8, 2011* (April 2012), available at http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

[5] See the project page for 2014-03, available at http://www.nerc.com/pa/stand/pages/project-2014-03-revisions-to-top-and-iro-standards.aspx.

FERC Directives

In approving the original TOP and IRO standards in Order No. 693, FERC directed future improvements that would require a minimum set of capabilities be made available to operators.[6] FERC indicated that the intent of the directive is to ensure operating entities have adequate tools to perform their real-time reliability functions.[7]

- P 905: *Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions.*
- P 906*: [t]he Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time.*
- P 1660: *We adopt our proposal to require the ERO to develop a modification [to TOP standards] related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System.*

Independent Experts Review Project (IERP) Report

In 2013, NERC retained a team of five industry experts to assess the quality of the enforceable body of standards and make recommendations for improvements that could be implemented by NERC and the industry.[8] Among the recommendations made by the panel of experts was the identification of potential risks to reliability that may not be adequately addressed in Reliability Standards. The report recommended resuming development of the Real-time Monitoring and Analysis Capabilities standards project.

Proposed TOP and IRO Standards

Since Project 2009-02 was initiated in 2009, many standards and definitions have been revised or developed that address real-time situational awareness issues. In particular, the revised TOP and IRO standards in Project 2014-03, which are pending regulatory approval, include key provisions for real-time situational awareness and operations planning. In reviewing the RTBPTF report recommendations for applicability in the current Project 2009-02 effort, the SAR DT considered the Project 2014-03 standards as noted in the Appendix.

The proposed TOP and IRO standards in Project 2014-03 provide requirements for performing monitoring and analysis through the definition of Real-time Assessment, Operational Planning Analysis, and the relevant requirements. Accordingly, additional requirements to perform monitoring or analysis will not be included in the scope for Project 2009-02. Furthermore, requirements for data exchange to support real-time monitoring and analysis will not be included in scope for Project 2009-02 because they are addressed through data specification requirements in IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3.

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[6] Order No. 693 at P 905 (approving IRO-002-1 and directing modifications) and P 1665 (approving TOP-006-1 and directing modifications.

[7] Additionally, in approving VAR-001-1 - Voltage and Reactive Control, the Commission directed NERC to develop modifications to the standard to require periodic performance of voltage stability analysis to assist in real-time operations. The commission clarified that this could be accomplished through online tools where available, or offline simulation tools.

- §1875: *...[w]e direct the ERO, through its Reliability Standards development process, ...to include requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations.*

VAR-001 was revised in the Project 2013-04, however the revised standard did not include a requirement for periodic performance of voltage stability analysis because voltage stability analysis is performed per SOL Methodology developed under FAC standards.

[8] See The Standards Independent Experts Review Project report. Available at www.nerc.com /pa/Stand/_layouts/xlviewer.aspx?id=/pa/Stand/Documents/P81_and%20IERP_Recommendations_for_Retirement_010815.xlsx.

Technical Conference

NERC and the SAR DT held a Technical Conference in Atlanta on June 4, 2015, to obtain industry input on reliability issues to be addressed in the proposed project. Participant subject matter experts representing a diverse mix of regional and functional entities shared their perspectives on the use of real-time situational awareness capabilities for reliable operations. There was consensus that many RTBPTF recommendations have been addressed in current or proposed TOP and IRO standards. However, Technical Conference participants agreed that issues identified by the RTBPTF pertaining to availability and information quality of real-time monitoring and analysis capabilities were still relevant.

Chapter 2 – Project Scope

The SAR DT has reviewed all recommendations from the RTBPTF and relevant recommendations from event reports, along with the existing body of standards, to identify remaining issues that should be in the scope for Project 2009-02. Table 1 below shows the resulting recommendations to be addressed. Additionally, the project will address outstanding FERC directives discussed in the preceding chapter.

Table 1: Report Recommendations to Address in Project 2009-02

Source	Recommendation	Discussion	Applicable Entity
2003 Blackout Report	Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators.	Project 2009-02 will develop requirements for real-time reliability monitoring and analysis capabilities to address issues not already addressed in other Reliability Standards. RTBPTF report recommendations will be considered in development.	RC, TOP, BA
2011 Southwest Outage Report	Recommendation 12 - [entities] should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2009-02 will develop requirements to improve the adequacy and operation of real-time monitoring and analysis capabilities. Requirements addressing the frequency that real-time tools run are contained in other standards and are not in the scope of this project.	RC, TOP, BA
RTBPTF Report	S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • Alarm Tools • Telemetry Data Systems • Network Topology Processor • State Estimator • Contingency Analysis	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. Prescription of specific tools is not in scope. Project approach is discussed below.	RC, TOP, BA as discussed below
RTBPTF Report	S7 - S8, S11-S12, S40 - Availability of various monitoring and analysis capability processes	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring ~~and analysis~~ capabilities are not available (i.e., not performing their intended function).	RC, TOP, BA

Project Purpose and Approach

Project 2009-02 will develop requirements for real-time monitoring and analysis capabilities used by operators in support of reliable System operations. Functional requirements for performing *monitoring* and *analysis* tasks are well established in Reliability Standards as discussed throughout this white paper. However, reliability could be improved by:

- Developing a common understanding of *monitoring* as it applies to real-time situational awareness of the BES,
- Providing operators with indication(s) of the quality of information being provided by *monitoring* and *analysis* capabilities, and

- Providing operators with notification(s) during unplanned loss of *monitoring* ~~and *analysis*~~ capabilities.

Project 2009-02 will develop requirements and definition(s), as needed, to accomplish these reliability objectives as discussed.

Real-time Situational Awareness Concept

From the RTBPTF Report:

> *Situational awareness, as RTBPTF understands it, means ensuring that accurate information on current system conditions, including the likely effects of future contingencies, is continuously available in a form that allows operators to quickly grasp and fully understand actual operating conditions and take corrective action when necessary to maintain or restore reliable operations.*

The Project 2009-02 SAR DT believes that situational awareness encompasses two broad capabilities: monitoring and analysis. To be effective in supporting real-time situational awareness, monitoring and analysis must:

- Be performed with sufficient frequency to allow operators to understand operating conditions and take corrective actions when necessary,
- Provide awareness of information quality to allow operators to assess the accuracy of information being received on system conditions and take corrective actions when necessary, and
- Indicate when monitoring or analysis processes are not operating normally or are unavailable in order to provide operator awareness of the accuracy of the information being provided.

Project 2009-02 will develop new requirements and definition(s), as needed, that support this concept of situational awareness without duplicating aspects that are already addressed in the existing and proposed body of Reliability Standards. As discussed in the preceding chapter, requirements for the Reliability Coordinator (RC), Transmission Operator (TOP), and Balancing Authority (BA) to perform monitoring and analysis are covered under existing and proposed TOP and IRO standards. Therefore, Project 2009-02 will focus on developing requirements to address information quality and operator awareness of real-time monitoring and analysis capabilities. Table 2 shows reliability objectives that should be addressed in requirements for this project.

Monitoring

Monitoring BES facilities in real-time is a primary function of the RCs, TOPs, and BAs and is addressed in existing and proposed TOP and IRO standards. For RCs, proposed IRO-002-4 states:

> *R3. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.*

For TOPs and BAs, proposed TOP-001-3 states:

> *R10. Each Transmission Operator shall perform the following as necessary for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area:*
>
> *10.1. Within its Transmission Operator Area, monitor Facilities and the status of Special Protection Systems, and*
>
> *10.2. Outside its Transmission Operator Area, obtain and utilize status, voltages, and flow data for Facilities and the status of Special Protection Systems.*

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

The SAR DT understands *monitoring* capabilities may include both alarming and information visualization. Project 2009-02 will aim to develop a consistent understanding of *monitoring* within the industry. The project will also address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of information being provided by a monitoring system, and indication when a monitoring system is not operating normally.

Analysis

The *analysis* component of the Real-time situational awareness concept is described by the definition of Real-time Assessment, which is pending FERC approval along with the proposed TOP and IRO standards. The proposed definition is as follows:

Real-time Assessment *- An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)*

Requirements for performing Real-time Assessments are contained in proposed IRO-008-2 and TOP-001-3:

Proposed IRO-008-2
R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

Proposed TOP-001-3
R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.

The SAR DT believes the proposed definition of Real-time Assessment and the requirements in proposed IRO-008-2 and TOP-001-3 provide RCs and TOPs with flexibility to determine which real-time tools, such as State Estimator, Contingency Analysis, and Stability Applications, are necessary to meet their real-time reliability functions. Consequently, prescriptive requirements for real-time tools are not in scope for Project 2009-02.

The project will address recommendations from Table 1 by developing requirements to ensure operators are provided with an indication of the quality of the analysis ~~provided by~~used in ~~a~~ Real-time Assessment~~s and notification when Real-time Assessment capabilities are not available~~.

Table 2: Project 2009-02 Reliability Objectives		
	Monitoring Capabilities	**Analysis Capabilities**
Quality	Provide operator with indication of information quality and procedures to address data quality issues.	Provide operator with indication of information quality and procedures to address analysis quality issues.

Availability	Provide operator with notification any time monitoring system is not operating normally.	~~Provide operator with notification any time Real-time Assessment capabilities are not available.~~ N/A

Appendix – Report Recommendations

The table below contains recommendations for improved real-time situational awareness capabilities found in relevant industry reports and how these recommendations have been addressed, if applicable. If recommendations have not been addressed fully, the table includes a description of how they should be addressed in Project 2009-02. The following industry reports are considered here[9]:

- 2003 Blackout Final Report
- 2011 Southwest Outage Report
- Real-time Tools Best Practices Task Force

Report Recommendation Mapping	
Report Recommendation	**Applicable Standard(s)**
2003 Blackout Final Report	
Recommendation 1-21, 23-46	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 22 - Evaluate and adopt better real-time tools for operators and reliability coordinators. Operating Committee to evaluate the real-time operating tools necessary for reliability operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices.	The Operating Committee established the RTBPTF to evaluate real-time operating tools and make recommendations for proposed standards. Project 2009-02 should consider these recommendations as discussed below.
2011 Southwest Outage Report	
Recommendation 1-10, 13-26	Report recommendations do not apply to Real-time reliability monitoring and analysis capabilities.
Recommendation 11 - TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS.	Project 2014-03 developed the proposed definition of Real-time Assessment and proposed TOP-003-3 Requirement R1 which describes the requirements for a data specification that will provide all of the data that a TOP needs in order to fulfill its reliability function. Together, these address capabilities and required data TOPs must have to ensure adequate situational awareness. **Real-time Assessment -** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-003-3, Requirement R1, Part 1.1**:

[9] *All industry reports are available on the 2009-02 Project Page: http://www.nerc.com/pa/Stand/Pages/Project-2009-02-Real-time-Reliability-Monitoring-and-Analysis-Capabilities.aspx.*

	A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator.
Recommendation 12 - TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.	Project 2014-03 developed a requirement for the performance of a Real-time Assessment for Transmission Operators. Standards developed in Project 2009-02 will address the adequacy of tools as described in this recommendation. **Proposed TOP-001-3, Requirement R13:** Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
Recommendation 27 - TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences.	Proposed definitions of Real-time Assessment (RTA) and Operational Planning Analysis (OPA) developed in Project 2014-03 specify that identified phase angle limitations must be considered and deal with applying phase angle information. Proposed TOP-002 Requirement R2 specifies that TOPs must have an Operating Plan(s) for next-day operations to address potential SOL exceedances identified in the OPA. Data specification requirements in approved IRO-010-1, proposed IRO-010-2, and proposed TOP-003-3 provide a means for RCs and TOPs to obtain phase angle information. **Proposed Definition: Operational Planning Analysis:** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed Definition: Real-time Assessment:** An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System

	Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1.
RTBPTF Report	
S1 - Mandate the following reliability tools as mandatory monitoring and analysis tools. • **Alarm Tools** • **Telemetry Data Systems** • **Network Topology Processor** • **State Estimator** • **Contingency Analysis**	Project 2009-02 will address requirements for Real-time monitoring and analysis capabilities. However, prescription of specific tools is not in scope.
S2 - Compile and maintain a list of all bulk electric system elements within RC's area of responsibility.	Not in scope. Reliability objective is accomplished through monitoring and analysis requirements as discussed below.
S3 - Add new requirements and measures pertaining to RC monitoring of the bulk electric system.	~~Addresses~~ Addressed in IRO standards (current and proposed). **IRO-002-2** R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. **IRO-003-2** R1. Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area. **Proposed IRO-002-4** R3. Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
S4 - Develop data-exchange standards.	Addressed in proposed TOP-001-3 and IRO-002-4. **Proposed TOP-001-3** R19. Each Transmission Operator shall have 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.

	R20. Each Balancing Authority shall have 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. **Proposed IRO-002-4** 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.
S5 - Develop data-availability standards and a process for trouble resolution and escalation.	Data availability and trouble resolution is addressed in IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. ... **Proposed IRO-010-2** R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
S6 - Develop a new weather data requirement related to situational awareness and real-time operational capabilities.	EOP-010-1 covers space weather dissemination. The SAR DT views monitoring other weather information as common utility practice that does not require a reliability standard.
S7 - Specify and measure minimum availability for alarm tools.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and

	alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and, alarming, and analysis tools are not available (i.e. not performing their intended function). Availability notification for analysis tools is addressed in IRO-008-1, and proposed IRO-008-2 proposed TOP-001-3 from Project 2014-30. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed IRO-008-2** R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.
S8 - Specify and measure minimum availability for network topology processor.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and , alarming, and analysis tools are not available (i.e. not performing their intended function).
S9 - Establish a uniform formal process to determine the "wide area view boundary" and show boundary data/results.	Wide-area is now a defined term. Recommendation has been addressed.
S10 - Develop compliance measures for verification of the usage of "wide-area overview display" visualization tools.	IRO standards revisions have addressed compliance measures.
S11 - Specify and measure minimum availability for state estimator, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and, alarming, and analysis tools are not available (i.e. not performing their intended function).
S12 - Specify and measure minimum availability for contingency analysis, including a requirement for solution quality.	The RTBPTF recommended a requirement be developed to provide operator awareness when key monitoring and alarming tools are not performing their intended functions. Project 2009-02 will address the recommendation to provide operator awareness when key monitoring, and alarming, and analysis tools are not available (i.e. not performing their intended function).
S13 - Specify criteria and develop measures for defining contingencies.	Not in scope; Addressed in approved TPL and FAC standards.

S14 - Perform one-hour-ahead power-flow simulations to assess approaching SOL and IROL violations and corresponding measures.	Requirements for assessing pre- and post-contingency system conditions are addressed in Real-time Assessment (RTA) and Operational Planning Analysis (OPA) definitions. Requirements for performing RTA and OPA are contained in proposed TOP-001-3, TOP-002-4, IRO-008-2, and approved IRO-008-1. **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **Proposed TOP-001-3** R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. **IRO-008-1** R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. **Proposed definition** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and

	Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
S15 - Provide real-time awareness of load-shed capability to address potential or actual IROL violations.	Addressed in proposed EOP-011-1, approved IRO-010-1 and proposed IRO-010-2 and TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s);

	2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... **Proposed TOP-003-3** R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. ... **Proposed IRO-010-2** R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to

	perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator.
S16 - Require BAs to monitor contingency reserves and calculate contingency reserves at a minimum periodicity of 10 seconds.	BA responsibilities for managing Contingency Reserve are addressed in the approved BAL-002-1 standard which is under revision in Project 2010-014. 1. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.
S17 - Revise the current-day operations requirements to delineate specific, independent requirements for monitoring operating and reactive reserves.	Addressed in VAR-001-4, BAL-002, and proposed IRO-002-4 and TOP-001-3. **VAR-001-4** R4. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. **BAL-002-1** R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. **Proposed IRO-002-4** **R3.** Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. **Proposed TOP-001-3** R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Special Protection Systems that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.
S18 - Establish document plans and procedures for conservative operations.	Addressed in proposed EOP-011-1 Requirement R1. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-

	reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions. R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2. Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

S19 - Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes.	Addressed in proposed TOP-001-3, and IRO-008-2 and the proposed definitions for Operational Planning Analysis and Real-time Assessment. **Proposed TOP-001-3** 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. R13. Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. R14. Each Transmission Operator shall initiate its Operating Plan to mitigate an SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. **Proposed IRO-008-2** R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. R5. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. **Proposed definition** **Operational Planning Analysis -** An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.) **Proposed definition** **Real-time Assessment** - An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be

	provided through internal systems or through third-party services.)
S20 - Develop formal operating guides (mitigation plans) and measures for each IROL and any SOL or other conditions having a potential impact on reliability.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.
S21 - Review and update operating guides (mitigation plans) **when day-ahead or current day studies indicate the potential need to implement an operating guide.**	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for

	the next-day provided by its Transmission Operators and Balancing Authorities.
S22 - Provide temporary operating guides (mitigation plans) with control actions for situations that could affect reliability but that have not been identified previously.	Addressed in proposed TOP-002-4 and IRO-008-2. **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.
S23 - Develop joint operating guides (mitigation plans) for situations that could require more than one RC or more than one TOP to execute actions.	Addressed in IRO-014-2, proposed IRO-014-3 and proposed IRO-008-2. **IRO-014-2** R1. Each Reliability Coordinator shall have Operating Procedures, Operating Processes, or Operating Plans for activities that require notification, exchange of information or coordination of actions that may impact other Reliability Coordinator Areas to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall collectively address the following: ... **Proposed IRO-014-3** R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: ... **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as

	a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.
S24 - Develop a formal procedure to document the processes for developing, reviewing, and updating operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S25 - Incorporate verifiable and traceable elements such as titles, document numbers, revision numbers, revision history, approvals, and dates when modifying operating guides (mitigation plans).	Not in scope; this is administrative in nature.
S26 - Write operating guides (mitigation plans) in clear, unambiguous language, leaving nothing to interpretation.	Not in scope. This is administrative in nature.
S27 - State the specific purpose of existence for each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S28 - Summarize the specific situation assessment and address the method of performing the assessment in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S29 - Identify all appropriate preventive and remedial control actions in each operating guide (mitigation plan).	Not in scope. This is administrative in nature.
S30 - Develop criteria in operating guides (mitigation plans) to support decisions regarding whether a specific control action should be taken.	Not in scope. This is administrative in nature.
S31 - Incorporate on-line tools that utilize on-line data when operating guides (mitigation plans) require calculations.	Not in scope. Recommendation is appropriate as a guideline rather than a reliability standard.
S32 - Make operating guides (mitigation plans) readily available via a quick-access method such as Web-based help, EMS display notes, or on-line help systems.	Not in scope. This is administrative in nature.
S33 - Provide the location, real-time status, and MWs of load available to be shed.	Addressed in proposed EOP-011-1 Requirement R1 Part 1.2.5 and proposed TOP-003-3. **Proposed EOP-011-1** R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

	1.2.6. Reliability impacts of extreme weather conditions. **Proposed TOP-003-3** R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. ...
S34 - Establish documented procedures for the reassessment and re-posturing of the system following an event.	Addressed in proposed TOP-002-4 and IRO-008-2, and approved EOP-005-2 and EOP-006-2. **Proposed TOP-002-4** R2. Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. R4. Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses: 4.1 Expected generation resource commitment and dispatch 4.2 Interchange scheduling 4.3 Demand patterns 4.4 Capacity and energy reserve requirements, including deliverability capability **Proposed IRO-008-2** R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ...

	EOP-006-2 R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S35 - Provide information to operators to maintain awareness of the availability and capability of the blackstart generators and transmission restoration paths.	Addressed in approved IRO-010-1, proposed TOP-003-3, proposed IRO-010-2, approved EOP-005-2, and approved EOP-006-2. **IRO-010-1** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. ... R1.6. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. ... **Proposed TOP-003-3** R1. Each Transmission Operator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include, but not be limited to: 1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data as deemed necessary by the Transmission Operator. ... **Proposed IRO-010-2** R1. The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: 1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses,

	Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. **EOP-005-2** R1. Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: ... R1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit. ... R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **EOP-006-2** R1. Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: ...
S36 - Plan and coordinate scheduled outages of blackstart generators and transmission restoration paths.	Addressed in approved EOP-005-2 and proposed IRO-017-1 - Outage Coordination. **EOP-005-2** R15. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. **Proposed IRO-017-1** R1. Each Reliability Coordinator shall develop, implement, and maintain an outage coordination process for generation

	and Transmission outages within its Reliability Coordinator Area. The outage coordination process shall: ...
S37 - Maintain a Critical Equipment Monitoring Document to identify tools and procedures for monitoring critical equipment.	Not in scope. This is administrative in nature.
S38 - Maintain event logs pertaining to critical equipment status for a period of one year.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be "installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools". Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S39 - Maintain a Critical Equipment Maintenance and Testing Document identifying tools and procedures for maintenance, modification, and testing of critical equipment.	Not in scope. This recommendation is to write a requirement for 'critical equipment', which the RTBPTF considered to be "installed equipment that makes up infrastructure and systems (including communication networks, data links, hardware, software applications, and data bases) that are directly used as critical real-time tools". Project 2009-02 will address capabilities, and not specific tools. Therefore the recommendation is not applicable to the project.
S40 - Monitor and maintain awareness of critical equipment status to ensure that lack of availability of critical equipment does not impair reliable operation.	Project 2009-02 will address the recommendation from the RTBPTF report to provide operator awareness when key monitoring and analysis capabilities are not available (i.e., not performing their intended function).

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 is the first posting of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	July 16 - August 17, 2015

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2015
45-day formal comment period with additional ballot	December 2015
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

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:** **Real-time Reliability Monitoring and Analysis Capabilities**
2. **Number:** **TOP-010-1**
3. **Purpose:** **Establish requirements for Real-time monitoring and analysis capabilities used by System Operators in support of 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

Rationale for Requirement R1: The Transmission Operator (TOP) uses a set of Real-time data identified in proposed standard 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 standards.

Requirement R1 Part 1.2 of this standard specifies the TOP shall include actions to coordinate resolution of Real-time data quality discrepancies in its Operating Process or Operating Procedure. These actions could be the same as the process to resolve data conflicts required by proposed TOP-003-3 Requirement R5 Part 5.2 provided that this process could resolve Real-time data quality issues.

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] [Time Horizon: Same Day Operations, Real-time Operations]*

- **1.1.** Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to:
  - **1.1.1.** Data outside of a prescribed data range;
  - **1.1.2.** Analog data not updated within a predetermined time period;
  - **1.1.3.** Data entered manually to override telemetered information; and
  - **1.1.4.** Data otherwise identified as invalid or suspect.

1.2. Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data.

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 Procedure or Operating Process in electronic or hard copy format meeting all provisions of Requirement R1, and 2) evidence the Transmission Operator implemented the Operating Procedure or Operating Process as called for in the Operating Procedure or Operating Process, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

Rationale for Requirement R2: The Balancing Authority (BA) uses a set of Real-time data identified in proposed standard TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other standards.

Requirement R2 Part 2.2 of this standard specifies the BA shall include actions to coordinate resolution of Real-time data quality discrepancies in its Operating Process or Operating Procedure. These actions could be the same as the process to resolve data conflicts required by proposed TOP-003-3 Requirement R5 Part 5.2 provided that this process could resolve Real-time data quality issues.

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] [Time Horizon: Same Day Operations, Real-time Operations]*

2.1. Criteria for evaluating potential Real-time data quality discrepancies including, but not limited to:

2.1.1. Data outside of a prescribed data range;

2.1.2. Analog data not updated within a predetermined time period;

2.1.3. Data entered manually to override telemetered information; and

2.1.4. Data otherwise identified as invalid or suspect.

2.2. Actions to coordinate resolution of Real-time data quality discrepancies with the entity(ies) responsible for providing the data.

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 Procedure or Operating Process in electronic or hard copy format meeting all provisions of Requirement R2, and 2)

evidence the Balancing Authority implemented the Operating Procedure or Operating Process as called for in the Operating Procedure or Operating Process, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R3. Each Transmission Operator shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Transmission Operator shall have evidence it provided its System Operators with indications of the quality of Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to, computer printouts, system specifications, or other evidence.

R4. Each Balancing Authority shall provide its System Operators with indication(s) of the quality of Real-time data necessary to perform its analysis functions and Real-time monitoring. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Balancing Authority shall have evidence it provided its System Operators with indications of the quality of Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to, computer printouts, system specifications, or other evidence.

Rationale for Requirements R5 and R6: Requirements R5 and R6 ensure the TOP's System Operators have procedures and receive indication(s) to address issues related to the quality of the analysis inputs used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other standards.

R5. Each Transmission Operator shall implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Same Day Operations, Real-time Operations]*

5.1. Criteria for evaluating the quality of any analysis used in its Real-time Assessments; and

5.2. Actions to resolve quality deficiencies in any analysis used in its Real-time Assessments.

M5. Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Procedure or Operating Process in electronic or hard copy format meeting all provisions of Requirement R5, and 2) evidence the Transmission Operator implemented the Operating Procedure or Operating Process as called for in the

Operating Procedure or Operating Process, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.

R6. Each Transmission Operator shall provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M6. Each Transmission Operator shall have evidence it provided its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessment capabilities. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

Rationale for Requirement R7: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An independent alarm process monitor is one that would not fail with a simultaneous failure of the alarm processor. A 'heartbeat' or 'watchdog' monitoring system may accomplish this objective.

R7. Each Transmission Operator and Balancing Authority shall utilize an independent 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: Same Day Operations, Real-time Operations]*

M7. Each Transmission Operator and Balancing Authority shall have evidence it utilized an independent alarm process monitor that provided notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor 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 through R4, and Requirement R7, and Measures M1 through M4, and Measure M7, 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 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 Requirements R5 and R6 and Measures M5 and M6 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	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 and Part 1.2.	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 and Part 1.2; 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	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

			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 and Part 2.2.	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 and Part 2.2; 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	N/A	N/A	The Transmission Operator did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its Real-time monitoring and Real-time Assessments.
R4.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its

				analysis functions and Real-time monitoring.
R5.	N/A	N/A	The Transmission Operator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include one of the elements listed in Part 5.1 and Part 5.2.	The Transmission Operator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include any of the elements listed in Part 5.1 and Part 5.2; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments.
R6.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.
R7.	N/A	N/A	N/A	The responsible entity did not utilize an independent 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

None

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to recommendations in Real-time Best Practices Task Force Report and FERC directives	N/A

Standard Attachments

None

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 existing and proposed TOP and IRO standards. As used in TOP and IRO standards, monitoring involves observing operating status and operating value(s) in Real-time for awareness of system conditions. Real-time monitoring includes 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.

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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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2009-02 Real-time Monitoring and Analysis Capabilities

This document provides the Standard Drafting Team's (SDT) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in Project 2009-02.

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 ERO Sanction Guidelines.

The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk

requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

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

Guideline (3) – Consistency among Reliability Standards
The Commission 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 - 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

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

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

VRF Justification

The requirements in IRO-018-1 and TOP-010-1 were developed to address certain issues related to the Real-time monitoring and analysis capabilities used by operators of the BES. IRO-018-1 contains five requirements applicable to Reliability Coordinators (RCs), while TOP-010-1 contains seven analogous requirements for Transmission Operators (TOPs) and Balancing Authorities (BAs). A Medium VRF is proposed for all requirements in both standards according to the guidelines as explained below.

VRF Justifications – IRO-018-1 (R1-R5) and TOP-010-1 (R1-R7)	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A. The requirements are not directly connected to conclusions from the 2003 Blackout, but rather address specific recommendations from NERC Technical Committees.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirements have no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. These are new requirements. The VRFs in IRO-018-1 are consistent with those contained in TOP-010-1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A VRF of Medium is consistent with the NERC VRF definition. The requirements in IRO-018-1 and TOP-010-1 address issues related to the quality and availability of monitoring and analysis capabilities used by RCs, TOPs, and BAs in maintaining reliable operations. Violation of any of these requirements could directly affect the ability to effectively monitor and control the Bulk Electric System. However, violation of any of these requirements is unlikely to lead to Bulk Electric System instability, separation, or cascading failures. Therefore, a VRF of Medium is appropriate.

VRF Justifications – IRO-018-1 (R1-R5) and TOP-010-1 (R1-R7)	
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. Each requirement contains one objective, therefore a single VRF is assigned to each requirement.

VSL Justification

Proposed VSLs – IRO-018-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	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 and Part 1.2.	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 and Part 1.2; 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.

VSL Justifications – IRO-018-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement 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 prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	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: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does 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 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.

Proposed VSLs – IRO-018-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its Real-time monitoring and Real-time Assessments.

VSL Justifications – IRO-018-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	The proposed VSL is worded consistently with the corresponding requirement.

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

Proposed VSLs – IRO-018-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 and Part 3.2.	The Reliability Coordinator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 and Part 3.2.; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure

			to maintain the quality of any analysis used in its Real-time Assessments.

VSL Justifications – IRO-018-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement 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 prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	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: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does 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 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.

Proposed VSLs – IRO-018-1, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.

VSL Justifications – IRO-018-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to 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 proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does 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 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.

Proposed VSLs – IRO-018-1, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not utilize an independent alarm

			process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

VSL Justifications – IRO-018-1, R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does 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 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.

Proposed VSLs – TOP-010-1, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	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	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 and Part 1.2.	of the elements listed in Part 1.1 and Part 1.2; 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.

VSL Justifications – TOP-010-1, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement 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 prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 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.
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.

Proposed VSLs – TOP-010-1, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	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 and Part 2.2.	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 any of the elements listed in Part 2.1 and Part 2.2.; 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.

VSL Justifications – TOP-010-1, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1	There is no prior compliance obligation related to the subject of this standard.

Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed 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.
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	The proposed VSL is not based on a cumulative number of violations.

Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

Proposed VSLs – TOP-010-1, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its Real-time monitoring and Real-time Assessments.

VSL Justifications – TOP-010-1, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of	There is no prior compliance obligation related to the subject of this standard.

Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to 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 2a: The proposed VSL is binary and assigned a Severe VSL.
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does 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 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	The proposed VSL is not based on a cumulative number of violations.

Cumulative Number of Violations	

Proposed VSLs – TOP-010-1, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with indication(s) of the quality of Real-time data used to perform its analysis functions and Real-time monitoring.

VSL Justifications – TOP-010-1, R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does 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 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.

Proposed VSLs – TOP-010-1, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include one of the elements listed in Part 5.1 and Part 5.2.	The Transmission Operator's Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments did not include any of the elements listed in Part 5.1 and Part 5.2.; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to maintain the quality of any analysis used in its Real-time Assessments.

VSL Justifications – TOP-010-1, R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement 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	There is no prior compliance obligation related to the subject of this standard.

Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to 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 2a: The proposed VSL is not binary.
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does 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 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	The proposed VSL is not based on a cumulative number of violations.

Cumulative Number of Violations	

Proposed VSLs – TOP-010-1, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with indication(s) of the quality of any analysis used in its Real-time Assessments.

VSL Justifications – TOP-010-1, R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does 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 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.

Proposed VSLs – TOP-010-1, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not utilize an independent alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

VSL Justifications – TOP-010-1, R7	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

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 proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does 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 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.

Rui Da Shu

From: Phan, Si Truc <Phan.Si_Truc@hydro.qc.ca>
Sent: Monday, November 23, 2015 9:59 AM
To: Guy V. Zito
Cc: Rui Da Shu
Subject: TR: Definition of Facility

For your information,
If you wish, it can be discussed at the meeting.
Si Truc

De : Jill Loewer [mailto:Jill.Loewer@utilitysvcs.com]
Envoyé : 23 novembre 2015 09:05
À : Phan, Si Truc; Brian Robinson
Objet : RE: Definition of Facility

Si Truc,
Thank you for your comments regarding the issue with PRC-004-4 and the terms Composite Protection System and Misoperation.

Though the Alignment of Terms Standard Drafting Team is not planning to draft a SAR to modify the definition of either term, the issue you raise did come up during our project team meetings. Our team is drafting a "Phase 2" document which will be forwarded to the NERC Standards Committee for consideration and one of the recommendations involves "correct and consistent use of capitalization to indicate a NERC defined term". It is our teams belief that capitalization of (or failure to capitalize) a defined term has great significance and should occur only when the term is intended to have the NERC-defined meaning.

Do I have your permission to use your example in our teams "Phase 2" document write up?

Also, would you like to elaborate on your comments made during the "Consideration of Comments" phase of the Glossary terms modification balloting regarding the change to the following terms and the resulting Facility SAR I am working on? Or should we use these issues raised verbatim in our Phase 2 document?

> *Term 17: Generator Operator*
> *Considering the definition of Facility listed in the Glossary, a TOP operating a synchronous condenser or shunt compensator, which generates Mvars, could potentially qualify as operating a "generating Facility". Would the TOP therefore be under an obligation to register as a GOP? Even though Footnote 3 on page 6 preceding mentions that "the clarity and content of the current definition could be improved", and a SAR will be drafted, this should be taken care of now under this project.*
>
> *Term 18: Generator Owner*
> *Considering the definition of Facility given in the Glossary, a TO owning a synchronous condenser or shunt compensator, which generates Mvars, could potentially qualify as owning a "generating Facility". Would the TO, therefore, be under an obligation to register as a GO? Even though Footnote 4 on page 7 preceding mentions that "the clarity and content of the current definition could be improved", and a SAR will be drafted, this should be taken care of now under this project.*
>
> *Term 50: Transmission Operator*

Suggest to clearly define 'Facilities' to prevent the confusion from TOP versus GOP. We recognize the effort that is mentioned in Footnotes 3 and 4 on pages 6 and 7, but the revisions should be done under this project.

Term 51: Transmission Owner
Suggest to clearly define 'Facilities' to prevent the confusion from TO versus GO. We recognize the effort that is mentioned in Footnotes 3 and 4 on pages 6 and 7, but the revisions should be done under this project.

Give me a call if you would like to discuss further.

Thank you.

Jill Loewer

Senior Compliance Analyst
Utility Services
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From: Phan, Si Truc [mailto:Phan.Si_Truc@hydro.qc.ca]
Sent: Friday, November 20, 2015 4:03 PM
To: Brian Robinson
Cc: Jill Loewer
Subject: RE: Definition of Facility

Brian,
Hopes everything is going well.
Thanks you to Jill to acknowledge our concern of 'Facility' definition.

Attached a last week discussion of another terminology addressed to NERC. I wondered if it can be discussed in this forum or not? Please advise.
Thanks in advance

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Si Truc PHAN, eng.
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De : Brian Robinson [mailto:Brian.Robinson@utilitysvcs.com]
Envoyé : 19 novembre 2015 12:17
À : Phan, Si Truc
Cc : Jill Loewer
Objet : Definition of Facility

Good Morning Si Truc,

One of our staff members, Jill Loewer, is a member of the Alignment of Terms drafting team and has actually been tasked with initiating Phase 2 of the project. Jill is responsible for drafting the SAR to revise the definition of Facility. Jill is reaching out to individuals that commented on the use of Facility in the GO/GOP definitions to make sure that their concerns are addressed in the SAR. I believe during the RSC meeting that you had a concern that a TO/TOP may be captured as a GO/GOP because of a sync. Condenser or shunt that generates Vars.

Here is the comment Jill pulled from the NPCC comment form:

Considering the definition of Facility listed in the Glossary, a TOP operating a synchronous condenser or shunt compensator, which generates Mvars, could potentially qualify as operating a "generating Facility". Would the TOP therefore be under an obligation to register as a GOP? Even though Footnote 3 on page 6 preceding mentions that "the clarity and content of the current definition could be improved", and a SAR will be drafted, this should be taken care of now under this project.

Jill wanted to make sure that there was no additional information you would like to add to this comment to be included in the SAR. Just let her know if you would like to expand upon this with additional information.

Thank you.

Brian Robinson
Manager of Technical Services
Utility Services

t: (802) 241-1400
c: (802) 793-7128
f: (866) 214-8632
brian.robinson@utilitysvcs.com

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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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 19, 2015
SAR posted for comment	August 24, 2015

Anticipated Actions	Date
45-day formal comment period with ballot	October 2015
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. Title: Transmission Vegetation Management

2. Number: FAC-003-4

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

4. Applicability:

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

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

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3

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

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

4.2.2. Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Authority.

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

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

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

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

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

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Authority; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan.

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather

[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

1.1 An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

2.1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]

2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

2.4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

---

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

[8] *Id.*

[9] See footnote 4.

[10] See footnote 5.

[11] See footnote 6.

[12] *Id.*

[13] *Id.*

M2. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to

prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

[14] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[15] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

7.10. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless

directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

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

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;

- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a

			transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority	The responsible entity experienced a confirmed vegetation threat and did not notify the control center

			for that applicable line, but there was intentional delay in that notification.	holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- Link to FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions
2	May 9, 2013	Board of Trustees adopted the	Revisions

[16] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

		modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard becomes enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 becomes enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) will become enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	Projected initial posting October 2015	Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.0ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft
345	362	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.7ft
230	242	4.0ft	4.1ft	4.2t	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.6ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.5ft

* Such lines are applicable to this standard only if PA has determined such per FAC-014 (refer to the Applicability Section above)

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

[17] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[18] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[19]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[20]	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m	MVCD meters Over 304.8 m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8 m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3692m up to 4267m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m
345	362	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	0.9m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	.07m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m

* Such lines are applicable to this standard only if PA has determined such per FAC-014 (refer to the Applicability Section above)

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

[19] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[20] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[21]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[21] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Authorities may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Authority in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a

technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspections:
The current glossary definition of this NERC term is being modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team comprised NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation require adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the

greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:
R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner

to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*

2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

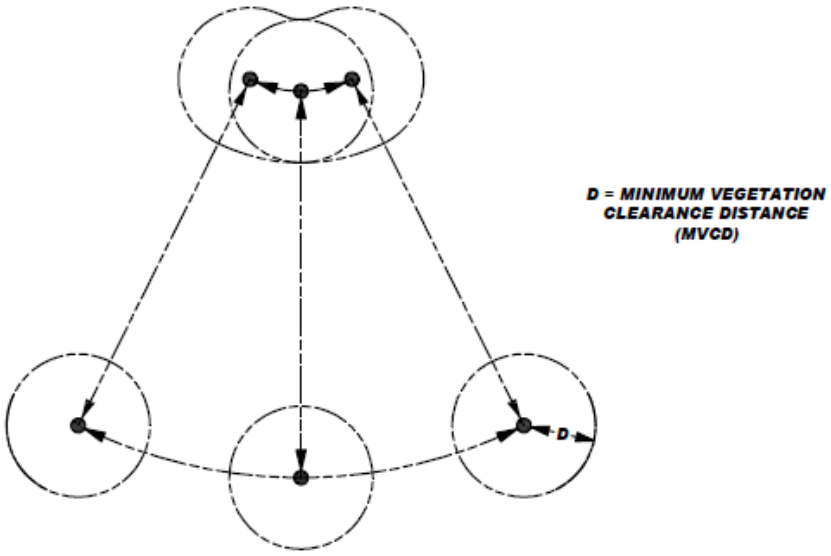


Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching

authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the

applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once

during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete it's an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces

the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s)” and “applicable line(s)” can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1 and R2:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner’s vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Standard Development Timeline

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

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	August 19, 2015
SAR posted for comment	August 24, 2015

Anticipated Actions	Date
45-day formal comment period with ballot	October 2015
10-day final ballot	January 2016
NERC Board (Board) adoption	February 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. Title: Transmission Vegetation Management

2. Number: FAC-003-~~4~~3

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

4. Applicability:

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

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

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3

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

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

4.2.2. Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning ~~Coordinator~~ Authority.

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

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

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

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

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

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning ~~Coordinator~~Authority; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

~~**5.**~~ **Effective Date:** See Implementation Plan. ~~The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.~~

~~**6.** Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.~~

~~**7.** Entities must comply with the "Compliance" section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.~~

~~**8.**~~**5.** ~~The "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" are provided for informational purposes. They are designed to convey guidance from NERC's various activities. The "Guideline and Technical Basis" section and text boxes with "Examples" and "Rationale" are not intended to establish new Requirements under NERC's Reliability Standards or to~~

[2] *Id.*

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

modify the Requirements in any existing NERC Reliability Standard. Implementation of the "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" is not a substitute for compliance with Requirements in NERC's Reliability Standards."

Effective Dates

Generator Owners

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Transmission Owners [transferred from FAC-003-2]

This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

~~4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date.~~

~~5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.~~

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the

interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);

- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

1.1 An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

[7] *Id.*

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*

2.1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]

2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

2.4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

M2. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

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[8] *Id.*
[9] See footnote 4.
[10] See footnote 5.
[11] See footnote 6.
[12] *Id.*
[13] *Id.*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar

year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

7.10. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the

[14] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[15] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

~~For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement Authority.~~

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

1.2. Evidence Retention:

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

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

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.~~Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-

compliance until found compliant or for the time period specified above, whichever is longer.

~~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

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Violation Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~Periodic Data Submittal~~

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

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;

- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a

			transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority	The responsible entity experienced a confirmed vegetation threat and did not notify the control center

			for that applicable line, but there was intentional delay in that notification.	holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

- Link to FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to	Revisions

		obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 20132	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard becomes enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 becomes enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) will become enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	Projected initial posting October 2015	Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for	Revisions

[16] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

		flashover distances between conductors and vegetation.	

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	~~8.2~~11.6ft	~~8.33~~11.7ft	~~8.61~~11.9ft	~~8.89~~12.1ft	~~9.17~~12.2ft	~~9.45~~12.4ft	~~9.73~~12.6ft	~~10.01~~12.8ft	~~10.29~~13.0ft	~~10.57~~13.1ft	~~10.85~~13.3ft	~~11.13~~13.5ft	13.7ft	13.9ft	14.0ft
500	550	7.0~~5.15~~ft	7.1~~5.25~~ft	~~5.45~~7.2ft	~~5.66~~7.4ft	~~5.86~~7.5ft	~~6.07~~7.6ft	~~6.28~~7.8ft	~~6.49~~7.9ft	~~6.7~~8.1ft	~~6.92~~8.2ft	8.3~~7.13~~ft	~~7.35~~8.5ft	8.6ft	8.8ft	8.9ft
345	362	~~3.19~~4.3ft	~~3.26~~4.3ft	~~3.39~~4.4ft	~~3.53~~4.5ft	~~3.67~~4.6ft	~~3.82~~4.7ft	~~3.97~~4.8ft	~~4.12~~4.9ft	~~4.27~~5.0ft	~~4.43~~5.1ft	~~4.58~~5.2ft	~~4.74~~5.3ft	5.4ft	5.5ft	5.6ft
287	302	~~3.88~~5.2ft	~~3.96~~5.3ft	~~4.12~~5.4ft	~~4.29~~5.5ft	~~4.45~~5.6ft	~~4.62~~5.7ft	~~4.79~~5.8ft	~~4.97~~5.9ft	~~5.14~~6.1ft	~~5.32~~6.2ft	~~5.50~~6.3ft	~~5.68~~6.4ft	6.5ft	6.6ft	6.7ft
230	242	~~3.03~~4.0ft	~~3.09~~4.1ft	~~3.22f~~4.2t	~~3.36~~4.3ft	~~3.49~~4.3ft	~~3.63~~4.4ft	~~3.78~~4.5ft	~~3.92~~4.6ft	~~4.07~~4.7ft	~~4.22~~4.8ft	~~4.37~~4.9ft	~~4.53~~5.0ft	5.1ft	5.2ft	5.3ft
161*	169	~~2.05~~2.7ft	~~2.09~~2.7ft	~~2.19~~2.8ft	~~2.28~~2.9ft	~~2.38~~2.9ft	~~2.48~~3.0ft	~~2.58~~3.0ft	~~2.69~~3.1ft	~~2.8~~3.2ft	~~2.91~~3.3ft	~~3.03~~3.3ft	~~3.14~~3.4ft	3.5ft	3.6ft	3.6ft
138*	145	~~1.74~~2.3ft	~~1.78~~2.3ft	~~1.86~~2.4ft	~~1.94~~2.4ft	~~2.03~~2.5ft	~~2.12~~2.5ft	~~2.21~~2.6ft	~~2.3~~2.7ft	~~2.4~~2.7ft	~~2.49~~2.8ft	~~2.59~~2.8ft	~~2.7~~2.9ft	3.0ft	3.0ft	3.1ft
115*	121	~~1.44~~1.9ft	~~1.47~~1.9ft	~~1.54~~1.9ft	~~1.61~~2.0ft	~~1.68~~2.0ft	~~1.75~~2.1ft	~~1.83~~2.1ft	~~1.91~~2.2ft	~~1.99~~2.2ft	~~2.07~~2.3ft	~~2.16~~2.3ft	~~2.25~~2.4ft	2.5ft	2.5ft	2.6ft
88*	100	~~1.18~~1.5ft	~~1.21~~1.5ft	~~1.26~~1.6ft	~~1.32~~1.6ft	~~1.38~~1.7ft	~~1.44~~1.7ft	~~1.5~~1.8ft	~~1.57~~1.8ft	~~1.64~~1.8ft	~~1.71~~1.9ft	~~1.78~~1.9ft	~~1.86~~2.0ft	2.0ft	2.1ft	2.1ft
69*	72	~~0.84~~1.1ft	~~0.86~~1.1ft	~~0.90~~1.1ft	~~0.94~~1.2ft	~~0.99~~1.2ft	~~1.03~~1.2ft	~~1.08~~1.2ft	~~1.13~~1.3ft	~~1.18~~1.3ft	~~1.23~~1.3ft	~~1.28~~1.4ft	~~1.34~~1.4ft	1.4ft	1.5ft	1.5ft

* Such lines are applicable to this standard only if P~~A~~C has determined such per FAC-014 (refer to the Applicability Section above)

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

[17] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[18] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[19]~~7~~

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[8][20]	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m	MVCD meters Over 304.8 m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8 m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3692m up to 4267m
765	800	3.65m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m
500	550	~~1.57~~2.1m	~~1.6~~2.2m	~~1.66~~2.2m	~~1.73~~2.3m	~~1.79~~2.3m	~~1.85~~2.3m	~~1.91~~2.4m	~~1.98~~2.4m	~~2.04~~2.5m	~~2.~~2.~~11~~.5m	~~2.17~~2.5m	~~2.24~~2.6m	2.6m	2.7m	2.7m
345	362	~~0.97~~1.3m	~~0.99~~1.3m	~~1.0~~1.3m	~~1.08~~1.4m	~~1.12~~1.4m	~~1.16~~1.4m	~~1.21~~1.5m	~~1.26~~1.5m	~~1.30~~.5m	~~1.35~~1.6m	~~1.40~~1.6m	~~1.44~~1.6m	1.6m	1.7m	1.7m
287	302	~~1.18~~1.6m	~~0.88~~1.6m	~~1.26~~1.7m	~~1.31~~1.7m	~~1.36~~1.7m	~~1.41~~1.7m	~~1.46~~1.8m	~~1.51~~1.8m	~~1.57~~1.9m	~~1.62~~1.9m	~~1.68~~1.9m	~~1.73~~2.0m	2.0m	2.0m	2.1m
230	242	~~0.92~~1.2m	~~0.94~~1.3m	~~0.98~~1.3m	~~1.02~~1.3m	~~1.06~~1.3m	~~1.11~~1.3m	~~1.15~~1.4m	~~1.19~~1.4m	~~1.24~~1.4m	~~1.29~~1.5m	~~1.33~~1.5m	~~1.38~~1.5m	1.6m	1.6m	1.6m
161*	169	~~0.62~~0.8m	~~0.64~~0.8m	~~0.67~~0.9m	~~0.69~~0.9m	~~0.73~~0.9m	~~0.76~~0.9m	~~0.79~~0.9m	~~0.82~~1.0m	~~0.85~~1.0m	~~0.89~~1.0m	~~0.92~~1.0m	~~0.96~~1.0m	1.1m	1.1m	1.1m
138*	145	~~0.53~~0.7m	~~0.54~~0.7m	~~0.57~~0.7m	~~0.59~~0.7m	~~0.62~~0.7m	~~0.65~~0.7m	~~0.67~~0.8m	~~0.70~~0.8m	~~0.73~~0.8m	~~0.76~~0.9m	~~0.79~~0.9m	~~0.82~~0.9m	0.9m	0.9m	0.9m
115*	121	~~0.44~~0.6m	~~0.45~~0.6m	~~0.47~~0.6m	~~0.49~~0.6m	~~0.51~~0.6m	~~0.53~~0.6m	~~0.56~~0.6m	~~0.58~~0.7m	~~0.61~~.07m	~~0.63~~0.7m	~~0.66~~0.7m	~~0.69~~0.7m	0.8m	0.8m	0.8m
88*	100	~~0.36~~0.4m	~~0.37~~0.4m	~~0.38~~0.5m	~~0.40~~0.5m	~~0.42~~0.5m	~~0.44~~0.5m	~~0.46~~0.6m	~~0.48~~0.6m	~~0.50~~0.6m	~~0.52~~0.6m	~~0.54~~0.6m	~~0.57~~0.6m	0.6m	0.6m	0.6m
69*	72	~~0.26~~0.3m	~~0.26~~0.3m	~~0.27~~0.3m	~~0.29~~0.4m	~~0.30~~0.4m	~~0.31~~0.4m	~~0.33~~0.4m	~~0.34~~0.4m	~~0.36~~0.4m	~~0.37~~0.4m	~~0.39~~0.4m	~~0.41~~0.4m	0.4m	0.5m	0.5m

* Such lines are applicable to this standard only if ~~PC~~ PA has determined such per FAC-014 (refer to the Applicability Section above)

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the NERC Advisory posted on May 14, 2015.*

[19] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[20] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[2~~1~~7]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[21] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section ~~The first two sentences of the Effective Dates section~~ is standard language used in most NERC standards to cover the general effective date and ~~s sufficient to c~~covers the vast majority of situations. ~~Five~~ A special case~~s are needed to~~ covers effective dates for (1) ~~individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those~~ lines initially becoming subject to the Standard, (2) ~~which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those~~ lines ~~which are~~ changing i~~n a manner that removes their~~ applicability ~~to~~within the standard.

The special case is needed because the Planning Authorities may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Authority in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

~~Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.~~

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013

05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

~~Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.~~

~~Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.~~

~~Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.~~

~~Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.~~

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This ~~modified~~ definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the ~~revised~~ current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional

easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

~~The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.~~

Explanation for revising the definition of Vegetation Inspections:
The current glossary definition of this NERC term is being modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

~~The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.~~

Explanation of the ~~definition~~ derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777. ~~Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.~~

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team comprised NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation require adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the

greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. ~~As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and High for R2.~~

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations~~ as described more fully in the Technical Reference document.~~.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

~~The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.~~

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an

applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. ~~In the Technical Reference document more figures and explanations of conductor dynamics are provided.~~

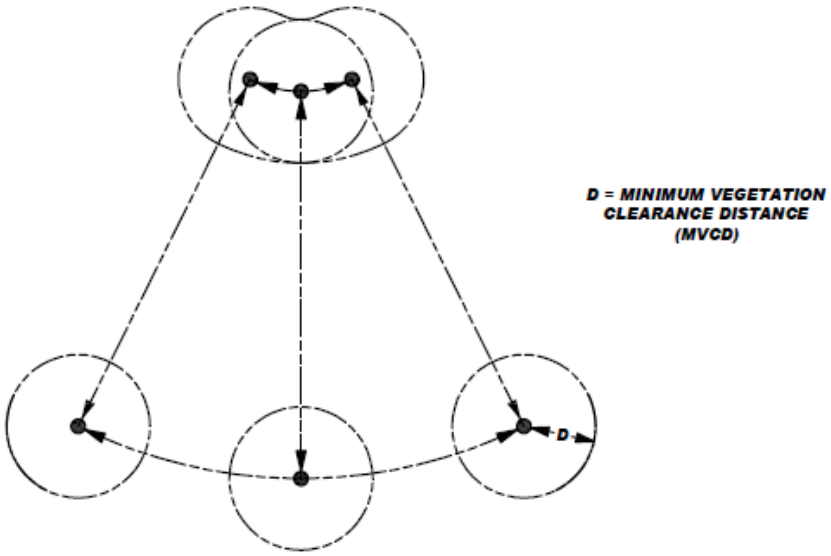


Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission

Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in

acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1 and R2:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. ~~See Figure~~

Rationale for R4:
This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:
Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

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Implementation Plan for FAC-003-4 — Transmission Vegetation Management

Requested Approval
FAC-003-4 – Transmission Vegetation Management

Requested Retirement
FAC-003-3 – Transmission Vegetation Management

Prerequisite Approvals
None.

Defined Terms in the NERC Glossary
None.

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 3 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 3 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Note

A line operated below 200kV, designated by the Planning Authority as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Authority or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.

A line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Standard for Retirement

FAC-003-3	11:59:59 p.m. on the day immediately prior to the Effective Date of FAC-003-4 in the particular jurisdiction in which the FAC-003-4 standard is becoming effective.

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Standards Authorization Request Form

When completed, email this form to:
Barbara.Nutter@nerc.net

For questions about this form or for assistance in completing the form, call Barb Nutter at 404-446-9692.

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:	FAC-003-4		
Date Submitted:	August 19, 2015		
SAR Requester Information			
Name:	Minimum Vegetation Clearance Distances (MVCD) Advisory Group [Ron Adams]		
Organization:	Duke Energy		
Telephone:	(704) 382-7338	E-mail:	Ron.adams@duke-energy.com
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?):
Correct the Gallet equation gap factors to reflect new information from Electric Power Research Institute (EPRI) study.
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to address the findings of the EPRI report in the FAC-003 Reliability Standard.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Provide the appropriate minimum vegetation clearances distances within the FAC-003 standard.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify FAC-003-3 to reflect the findings of the EPRI study.
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.)
At the time the FAC-003-3 Reliability Standard was filed there was some question regarding the gap factors contained in the Gallet equation. To validate the gap factors, NERC contracted with EPRI to complete further studies. The preliminary report indicates the need for a modification to the gap factors. The drafting team will be modifying the standard based on the final report, which was published on July 21, 2015. Click here for: the final EPRI report.

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.
☒	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
N/A	

Related Standards	

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
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WECC	N/A

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Organization:	Duke Energy		
Telephone:	(704) 382-7338	E-mail:	Ron.adams@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to existing Standard		☐ Withdrawal of existing Standard ☐ Urgent Action	

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Related Standards	
Standard No.	Explanation
N/A	

Related Standards	

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
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MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

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Reliability Standard PRC-012-2 Remedial Action Schemes Question & Answer Document

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)

November 2015

RELIABILITY | ACCOUNTABILITY






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Attachment A – Project Roster 7

Question & Answer for PRC-012-2

The Project 2010-05.3 Phase 3 of Special Protection Systems: Remedial Action Schemes (RAS) standard drafting team (SDT) developed this Question & Answer document to explain the key concepts incorporated into Reliability Standard PRC-012-2.

1. Why is the Remedial Action Scheme (RAS) review assigned to the Reliability Coordinator?

NERC Reliability Standards require accountability; consequently, they must be applicable to specific users, owners, and operators of the Bulk-Power System. The NERC white paper suggested Reliability Coordinators (RCs) and Planning Coordinators (PCs) for RAS-review responsibility. The SDT considered the suggestion and ultimately chose the Reliability Coordinator because of the RC has the widest possible view of the System of any operating or planning entity. Some Regions have as many as 30 PCs for one RC while other Regions or other System footprints have a single PC and RC for the same area. Overall, there are 16 RCs and approximately 80 PCs in North America. The large RC geographic oversight will minimize fragmentation of the regional reviews currently administered by the Regions and promote continuity.

The RC is the best-suited functional entity to perform the Remedial Action Scheme (RAS) review because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The Wide Area purview better facilitates the evaluation of interactions among separate RAS, as well as interactions among RAS and other protection and control systems. The selection of the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator, Transmission Planner, or other entities involved in the planning or implementation of a RAS. The RC is also less likely to be a stakeholder in any given RAS and can therefore maintain objective independence.

The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. The RC may request aid in RAS reviews from other parties such as the Planning Coordinator(s) or regional technical groups; however, the RC retains responsibility for compliance with the requirement.

2. Why is the 60 month evaluation of Requirement R4 assigned to the Planning Coordinator?

Requirement R4 states that an evaluation of each RAS must be done at least every 60 calendar months to verify the continued effectiveness and coordination of the RAS, its inadvertent operation performance, and the performance for a single component failure. The items that must be addressed in the evaluations include: 1) RAS mitigation of the System condition(s) or event(s) for which it was designed; 2) RAS avoidance of adverse interactions with other RAS and with protection and control systems; 3) the impact of inadvertent operation; and 4) the impact of a single component failure. The evaluation of these items involves modeling and studying the interconnected transmission system, similar to the planning analyses performed by PCs.

3. Why is the Planning Coordinator not required to perform an annual evaluation of RAS performance?

TOP-1-3 Requirement R13 requires Balancing Authorities (BA) and Transmission Owners (TO) to perform operational reliability assessments (e.g., real time contingency analysis (RTCA), day-ahead, seasonal) that include data describing new or degraded RAS. In addition, IRO-005-4 requires RCs to share any pertinent data, such as data from RAS, with potentially affected BAs and TOs. Operating horizon assessments that include RAS are already required by other standards, so an additional requirement duplicating that effort is not necessary.

TPL-001-4 Requirement R2 also requires TPs and PCs to perform annual planning assessments of the near-term transmission planning horizon. Requirement R2 Part 2.7.1 acknowledges that new, modified, or removed RAS may be part of a corrective action plan (CAP) used to fulfill Table 1 performance requirements. Short-term (annual) planning horizon assessments are already required by the TPL-001-4 standard, including RAS, so an additional requirement duplicating that effort is not necessary.

4. Why do RAS need to be reviewed and approved by a group other than the RAS-entity?

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the Bulk Electric System (BES) if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue or to achieve an economic or operational advantage, and could introduce reliability risks that may not be apparent to the RAS-entities. An independent review and approval is an objective and effective means of identifying risks and recommending RAS modifications when necessary.

5. What is required for RAS "single component failure" and why?

The existing PRC-012-1 Requirement 1 R1.3 states "Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0." If a RAS is installed to satisfy the performance requirements of a NERC Reliability Standard, it is necessary that its operation, under the conditions and events for which it is designed to operate, be ensured in the operational realm as well as in the planning realm. Requirement R4, Part 4.1.4 and Attachment 1 of PRC-012-2 reaffirms this objective by stating: "a single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS was designed."

Acceptable methods for achieving this BES performance objective include the following:

- Providing redundancy of RAS components listed below:
  - Protective or auxiliary relays used by the RAS
  - Communications systems necessary for correct operation of the RAS
  - Sensing devices used to measure electrical quantities used by the RAS
  - Station dc supply associated with RAS functions
  - Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices

- Computers or programmable logic devices used to analyze information and provide RAS operational output

- Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation would not be an issue if tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.
- Using alternative automatic actions to back up failures of single RAS components.
- Manual backup operations, using planned System adjustments such as transmission configuration changes and re-dispatch of generation if such adjustments are executable within the time duration applicable to the facility ratings.

When a component failure occurs, the resulting BES performance will depend on what RAS component failed and how critical it is to the functions of the RAS. This risk can only be evaluated on an individual basis through the review process.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Limited impact schemes are not subject to the single component failure aspect of Requirement R4, Part 4.1.4.

6. What is required for RAS "inadvertent operation" and why?

The possibility of inadvertent operation of a RAS during System events and conditions that are not intended to activate its operation must be considered. The existing PRC-012-1 Requirement 1, R1.4 states that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed and not exceed TPL-003-0. The drafting team clarified that the inadvertent operation to be considered would only be caused by the malfunction of a single RAS component. It is therefore possible to design security against inadvertent operation into the RAS logic and hardware such that a malfunction of any one RAS component would be unable to cause a RAS inadvertent operation, or might limit inadvertent operation of a RAS in part.

The intent of Requirement R4, Part 4.1.3 is to require a RAS to be designed so that its whole or partial inadvertent operation due to a single component malfunction does not prevent the System from meeting the performance requirements for the same contingency for which the RAS was designed. If the RAS was installed for an extreme event in TPL-001-4 or for System conditions not defined in TPL-001-4, inadvertent operation must not prevent the System from meeting the performance requirements specified in Requirement R4, Parts 4.1.3.1 – 4.1.3.5, which are the performance requirements common to all planning events P0–P7.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective

date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process. Limited impact schemes are not subject to the single component malfunction aspect of Requirement R4, Part 4.1.3.

7. What is meant by RAS adverse interaction or coordination with other RAS and protection and control systems?

RAS are complex schemes that typically take actions to trip load or generation or reconfigure the System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take action. Though unusual, overlapping actions among RAS would have the potential to result in Cascading unless they were coordinated. Similarly, RAS operation can change System configuration and available fault duty, which can affect coordination with distance relay overcurrent ("fault detector") supervision and ground overcurrent protection. A third coordination example is RAS operational timing that must coordinate with automatic reclosing on a faulted line. Many RAS are intended to mitigate post-Contingency overloads. A short coordinating delay up to a few seconds is required to avoid initiating action until a System Fault can be detected and cleared by Protection System action. A delay of several minutes may be acceptable as long as it is compatible with the thermal characteristics of the overloaded equipment.

8. Why are RAS classifications not recognized in the standard?

RAS classification was suggested in the SPCS-SAMS report as a means to differentiate the reliability risks between planning and extreme RAS for continuity with PRC-012-1 R1.3; however, the standard drafting team concluded the classification is unnecessary. The distinction between planning and extreme RAS is captured in Requirement R4, Part 4.1.4 and Attachment 1, item III.4 of PRC-012-2 that relates to single component failure; consequently, there is no need to have a formal classification for this purpose.

Similarly, the standard drafting team concluded that the SPCS-SAMS distinction between significant and limited RAS was unnecessary for the purpose of maintaining continuity with PRC-012-1, and problematic due to the difficulty of drawing a universally satisfactory delineation in generally worded classification criteria. Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process.

Some Regions classify RAS to prescribe RAS design and review requirements specific to the Region. Avoiding RAS classifications in the proposed standard makes it possible to retain Regional Entity classifications and associated criteria without overlap and confusion.

9. What constitutes a functional modification of a RAS?

A functional modification to a RAS consists of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels (addition or removal)

RAS retirement or removal is a form of RAS functional modification. A RAS-entity must submit the RAS data specified in the "RAS Retirement" section of Attachment 1.

The following are examples of RAS functional changes:

1. Replacement of a RAS field device if the replacement requires changes in device custom logic.
2. Changes to the telecommunication infrastructure or communication facility, such as the replacement of a T1 multiplexor that carries RAS communication when such changes may be important to the timing of a RAS.
3. The addition or removal of mitigation actions within a RAS component.
4. The addition or removal of contingencies or System conditions for which a RAS was designed to operate.
5. Changes to the RAS design to account for station bus configuration changes.

The following examples are not considered RAS functional changes:

1. The replacement of a failed RAS component with an identical component, or a component that uses the same functionality as the failed component.
2. A firmware upgrade of a RAS component if the change does not require changes in the RAS implementation logic.

The Supplementary Material section of Reliability Standard PRC-012-2 also includes several additional examples of RAS changes that do and do not constitute functional modifications.

Attachment A – Project Roster

Project 2010-05.3 – Remedial Action Schemes		
	Participant	**Entity**
Chair	Gene Henneberg	NV Energy / Berkshire Hathaway Energy
Vice Chair	Bobby Jones	Southern Company
Member	Amos Ang	Southern California Edison
Member	Alan Engelmann	ComEd / Exelon
Member	Davis Erwin	Pacific Gas and Electric
Member	Sharma Kolluri	Entergy
Member	Charles-Eric Langlois	Hydro-Quebec TransEnergie
Member	Robert J. O'Keefe	American Electric Power
Member	Hari Singh	Xcel Energy
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Andrew Wills (Associate Counsel)	NERC

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standard PRC-012-2 Remedial Action Schemes Question & Answer Document

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)

~~August~~November 2015

RELIABILITY | ACCOUNTABILITY






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Question & Answer for PRC-012-2

The Project 2010-05.3 Phase 3 of Special Protection Systems: Remedial Action Schemes (RAS) standard drafting team (SDT) developed this Question & Answer document to explain the key concepts incorporated into Reliability Standard PRC-012-2.

1. Why ~~was the Reliability Coordinator chosen to perform~~is the Remedial Action Scheme (RAS) review~~?~~ assigned to the Reliability Coordinator?

NERC Reliability Standards require accountability; consequently, they must be applicable to specific users, owners, and operators of the Bulk-Power System. The NERC white paper suggested ~~Planning Coordinators (PCs) and~~ Reliability Coordinators (RCs) and Planning Coordinators (PCs) for RAS-review responsibility. The SDT considered the suggestion and ultimately chose the Reliability Coordinator because of the RC has the widest possible view of the System of any operating or planning entity. Some Regions have as many as 30 PCs for one RC while other Regions or other System footprints have a single PC and RC for the same area. Overall, there are 16 RCs and approximately 80 PCs in North America. The large RC geographic oversight will minimize fragmentation of the regional reviews currently administered by the Regions and promote continuity.

The RC is the best-suited functional entity to perform the Remedial Action Scheme (RAS) review because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. ~~This wide-area purview provides continuity in the review process and~~The Wide Area purview better facilitates the evaluation of interactions among separate RAS, as well as interactions among RAS and other protection and control systems. The selection of the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, ~~PC~~Planning Coordinator, Transmission Planner ~~(TP),~~ or other entities ~~that are likely to be~~ involved in the planning or implementation of a RAS. The RC is also less likely to be a stakeholder in any given RAS and can therefore maintain objective independence.

The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. The RC may request aid in RAS reviews from other parties such as the Planning Coordinator(s) or regional technical groups; however, the RC retains responsibility for compliance with the requirement.

2. Why is the 60 month evaluation of Requirement R4 assigned to the Planning Coordinator?

Requirement R4 states that an evaluation of each RAS must be done at least every 60 calendar months to verify the continued effectiveness and coordination of the RAS, its inadvertent operation performance, and the performance for a single component failure. The items that must be addressed in the evaluations include: 1) RAS mitigation of the System condition(s) or event(s) for which it was designed; 2) RAS avoidance of adverse interactions with other RAS and with protection and control systems; 3) the impact of inadvertent operation; and 4) the impact of a single component failure. The evaluation of these items involves modeling and studying the interconnected transmission system, similar to the planning analyses performed by PCs.

~~2.~~3. Why is the Planning Coordinator not required to perform an annual evaluation of RAS performance?

TOP-~~005-~~1-3 Requirement ~~R3~~R13 requires Balancing Authorities (BA) and Transmission Owners (TO) to perform operational reliability assessments (e.g., real time contingency analysis (RTCA), day-ahead, seasonal) that include data describing new or degraded RAS. In addition, IRO-005-~~1 Requirement R12~~4 requires RCs to share any pertinent data, such as data from RAS, with potentially affected BAs and TOs. Operating horizon assessments that include RAS are already required by other standards, so an additional requirement duplicating that effort is not necessary.

TPL-001-4 Requirement R2 also requires TPs and PCs to perform annual planning assessments of the near-term transmission planning horizon. Requirement R2 Part 2.7.1 acknowledges that new, modified, or removed RAS may be part of a corrective action plan (CAP) used to fulfill Table 1 performance requirements. Short-term (annual) planning horizon assessments are already required by the TPL-001-4 standard, including RAS, so an additional requirement duplicating that effort is not necessary.

~~3. Why is the five-year evaluation assigned to the Transmission Planner rather than the Reliability Coordinator?~~

~~Requirement R4 states that an evaluation of each RAS must be done at least every 60 calendar months to verify the continued effectiveness and coordination of the RAS, its inadvertent operation performance, and the performance for a single component failure. The items that must be addressed in the evaluations include: 1) RAS mitigation of the System condition(s) or event(s) for which it was designed; 2) RAS avoidance of adverse interactions with other RAS and with protection and control systems; 3) the impact of inadvertent operation; and 4) the impact of a single component failure. The evaluation of these items involves modeling and studying the interconnected transmission system, which is very similar to the planning analyses performed by the TPs. The RC is more focused on actual System conditions, not necessarily on the conditions for which a RAS was designed. The required evaluation is a detailed planning analysis and thus the TP is better suited than the RC to perform the evaluation.~~

4. Why do RAS need to be reviewed and approved by a group other than the RAS-~~owner?~~ entity?

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the Bulk Electric System (BES) if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue or to achieve an economic or operational advantage, and could introduce reliability risks that may not be apparent to the RAS-~~owners~~entities. An independent review and approval is an objective and effective means of identifying risks and recommending RAS modifications when necessary.

5. What is required for RAS "single component failure" and why ~~is it required?~~ ?

The existing PRC-012-1 Requirement 1 R1.3 states "Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0." If a RAS is installed to satisfy the performance requirements of a NERC Reliability Standard, it is necessary that its operation, under the conditions and events for which it is designed to operate, be ensured in the operational realm as well as in the planning realm. Requirement R4, Part 4.1.4 and Attachment 1 of PRC-012-2 reaffirms this objective by stating: "a single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS was designed."

Acceptable methods for achieving this BES performance objective include the following:

- Providing redundancy of RAS components listed below:
  - Protective or auxiliary relays used by the RAS
  - Communications systems necessary for correct operation of the RAS
  - Sensing devices used to measure electrical quantities used by the RAS
  - Station dc supply associated with RAS functions
  - Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices
  - Computers or programmable logic devices used to analyze information and provide RAS operational output
- Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation would not be an issue if tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.
- Using alternative automatic actions to back up failures of single RAS components.
- Manual backup operations, using planned System adjustments such as transmission configuration changes and re-dispatch of generation if such adjustments are executable within the time duration applicable to the facility ratings.

When a component failure occurs, the resulting BES performance will depend on what RAS component failed and how critical it is to the functions of the RAS. This risk can only be evaluated on an individual basis through the review process.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Limited impact schemes are not subject to the single component failure aspect of Requirement R4, Part 4.1.4.

6. What is required for RAS "inadvertent operation" and why?

The possibility of inadvertent operation of a RAS during System events and conditions that are not intended to activate its operation must be considered. The existing PRC-012-~~0~~1 Requirement 1, R1.4 states that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed and not exceed TPL-003-0. The drafting team clarified that the inadvertent operation to be considered would only be caused by the malfunction of a single RAS component. It is therefore possible to design security against inadvertent operation into the RAS logic and hardware such that a malfunction of any one RAS component would be unable to cause a RAS inadvertent operation, or might limit inadvertent operation of a RAS in part.

The intent of Requirement R4, Part 4.1.3 is to require a RAS to be designed so that its whole or partial inadvertent operation due to a single component malfunction does not prevent the System from meeting the performance requirements for the same contingency for which the RAS was designed. If the RAS was installed for an extreme event in TPL-001-4 or for System conditions not defined in TPL-001-4, inadvertent operation must not prevent the System from meeting the performance requirements specified in Requirement R4, Parts 4.1.3.1 – 4.1.3.5, which are the performance requirements common to all planning events P0–P7.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process. Limited impact schemes are not subject to the single component malfunction aspect of Requirement R4, Part 4.1.3.

7. What is meant by RAS adverse interaction or coordination with other RAS and protection and control systems?

RAS are complex schemes that typically take actions to trip load or generation or reconfigure the System. Many RAS depend on sensing specific ~~system~~System configurations to determine whether they need to arm or take action. Though unusual, overlapping actions among RAS would have the potential to result in Cascading unless they were coordinated. Similarly, RAS operation can change System configuration and available fault duty, which can affect coordination with distance relay overcurrent ("fault detector") supervision and ground overcurrent protection. A third coordination example is RAS operational timing that must coordinate with automatic reclosing on a faulted line. Many RAS are intended to mitigate post-Contingency overloads. A short coordinating delay up to a few seconds is required to avoid initiating action until a System Fault can be detected and cleared by Protection System action. A delay of several minutes may be acceptable as long as it is compatible with the thermal characteristics of the overloaded equipment.

8. Why are RAS classifications not recognized in the standard?

RAS classification was suggested in the SPCS-SAMS report as a means to differentiate the reliability risks between planning and extreme RAS for continuity with PRC-012-1 R1.3; however, the standard drafting team concluded the classification is unnecessary. The distinction between planning and extreme RAS is captured in Requirement R4, Part 4.1.4 and Attachment 1, item III.4 of PRC-012-2 that relates to single component failure; consequently, there is no need to have a formal classification for this purpose.

~~The~~Similarly, the standard drafting team concluded that the SPCS-SAMS distinction between significant and limited RAS was unnecessary for the purpose of maintaining continuity with PRC-012-1 ~~R1.3 which does not recognize such a distinction~~, and problematic due to the difficulty of drawing a universally satisfactory delineation in generally worded classification criteria. Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be

designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process.

Some Regions classify RAS to prescribe RAS design and review requirements specific to the Region. Avoiding RAS classifications in the proposed standard makes it possible to retain Regional Entity classifications and associated criteria without overlap and confusion.

9. What constitutes a functional modification of a RAS?

~~Any change in RAS logic, relay settings, control settings, or any other modification that affects overall RAS functionality, timing, or redundancy level are changes to functionality documented in the original submission for review. RAS modifications identified by a CAP developed pursuant to Requirement R6—beyond the substitution of components that preserve the original functionality—are functional changes.~~

A functional modification to a RAS consists of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels (addition or removal)

RAS retirement or removal is a form of RAS functional modification. A RAS-entity must submit the RAS data specified in the "RAS Retirement" section of Attachment 1.

The following are examples of RAS functional changes:

1. Replacement of a RAS field device if the replacement requires changes in ~~the physical design, settings, or~~ device custom logic.
2. Changes to the telecommunication infrastructure or communication facility, such as the replacement of a T1 multiplexor ~~within a~~that carries RAS ~~component station. Such~~communication when such changes ~~could affect~~may be important to the ~~throughput~~ timing of a RAS.
3. The addition or removal of mitigation actions within a RAS component.
4. The addition or removal of contingencies or System conditions for which a RAS was designed to operate.
5. Changes to the RAS design to account for station bus configuration changes.

The following examples are not considered RAS functional changes:

1. The replacement of a failed RAS component with an identical component~~.~~, or a component that uses the same functionality as the failed component.
2. A firmware upgrade of a RAS component if the change does not require changes in the RAS implementation ~~settings or custom~~ logic.

~~10. Why is the RAS-entity identified in the standard and what are its responsibilities?~~

~~The purpose of the RAS-entity is to be the single information conduit with the reviewing RC for all RAS-owners for each RAS. The RAS-entity needs to coordinate all review materials and any presentations. If all RAS equipment has a single owner, then the RAS-entity is the RAS-owner, and that owner speaks for itself.~~

~~A RAS can have more than one owner. The RAS-entity is always one of the RAS-owners and is designated by all RAS-owners. Historically, the owner of the RAS controller (most commonly a Transmission Owner) is the RAS-entity.~~

~~RAS-owners who are not the RAS-entity still have responsibilities as assigned in other NERC standards, such as equipment maintenance in PRC-005. In addition, when RAS modifications are needed; e.g., per Requirement R6 or Attachment 1, each RAS-owner must participate in developing a CAP and accept the specific responsibilities assigned to them in the CAP or otherwise as described in the revised Attachment 1.~~

The Supplementary Material section of Reliability Standard PRC-012-2 also includes several additional examples of RAS changes that do and do not constitute functional modifications.

Attachment A – Project Roster

Project 2010-05.3 – Remedial Action Schemes		
	Participant	**Entity**
Chair	Gene Henneberg	NV Energy / Berkshire Hathaway Energy
Vice Chair	Bobby Jones	Southern Company
Member	Amos Ang	Southern California Edison
Member	Alan Engelmann	ComEd / Exelon
Member	Davis Erwin	Pacific Gas and Electric
Member	Sharma Kolluri	Entergy
Member	Charles-Eric Langlois	Hydro-Quebec TransEnergie
Member	Robert J. O'Keefe	American Electric Power
Member	Hari Singh	Xcel Energy
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Andrew Wills (Associate Counsel)	NERC

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Implementation Plan for the Revised Definition of "Special Protection System"

Project 2010-05.3 – Remedial Action Scheme (RAS)

Requested Approval

- Definition of "Special Protection System"

Requested Retirement

- Existing definition of "Special Protection System"

Background

In Order No. 693, the Commission approved, among other things, the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"), which included NERC's currently definitions of Special Protection System and Remedial Action Scheme. The NERC Glossary currently defines a Special Protection System as:

> 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. An SPS 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 an SPS). Also called Remedial Action Scheme.

The currently-effective NERC Glossary definition for "Remedial Action Scheme" is a cross-reference to the definition of Special Protection System and reads: "See 'Special Protection System.'" This internal cross-references from Remedial Action Scheme to Special Protection System in lieu of a separate definition was developed to ensure that the terms are used interchangeably even where entities or an interconnection uses one term versus the other.

On February 3, 2015, NERC submitted a petition for approval of a revised definition of "Remedial Action Scheme" developed by the standard drafting team Project 2010-05.2 (SPS SDT). As explained in the petition, "[t]he defined terms 'Special Protection System' and 'Remedial Action Scheme' are currently used interchangeably throughout the NERC Regions and in various Reliability Standards, including prior versions of the Proposed Reliability Standards." In developing a solution for this inconsistency, the SPS SDT revised the definition of Remedial Action Scheme to incorporate a higher level of specificity for schemes that are appropriately considered Remedial Action Schemes, to provide more consistent identification of Remedial Action Schemes across the NERC Regions, and to state the relationship between Protection Systems and Remedial Action Schemes. NERC also submitted revisions to various

Reliability Standards by replacing the term "Special Protection System" with the newly revised "Remedial Action Scheme." As NERC stated, the "use of only one term in the NERC Reliability Standards will ensure proper identification of these systems and application of related Reliability Standards."

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

The petition for revisions to the Definition of "Remedial Action Scheme" and related Reliability Standards also anticipated revision of the definition of "Special Protection System" to cross-reference the newly revised definition of "Remedial Action Scheme." Coordination of the two terms was completed by the SPS SDT in this phase of the Project (Project 2010-05.3) and will implement the new definition of "Special Protection System" simultaneously with the effective date of the revised definition for "Remedial Action Scheme." By assigning simultaneous effective dates of the revised definition of "Special Protection System" and "Remedial Action Scheme," all references to either term in NERC or Regional Entity documents will refer to the same NERC Glossary definition.

Effective Dates

Where approval by an applicable governmental authority is required, the revised definition of Special Protection System shall become effective on the later of the effective date of the applicable governmental authority's order approving the revised definition of Special Protection System or the effective date of the revised definition of Remedial Action Scheme approved by the Commission on November 19, 2015.

Where approval by an applicable governmental authority is not required, the revised definition of Special Protection System shall become effective on the later of the day that it is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction, or the effective date of the revised definition of Remedial Action Scheme approved by the Commission on November 19, 2015.

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

Draft 2 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, and PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS/SPS-related standards. This draft contains nine requirements and measures, the associated rationale boxes and corresponding technical guidelines. There are also three attachments within the draft standard that are incorporated via references in the requirements. This draft of PRC-012-2 is posted for a 45-day formal comment period with a parallel ballot in the last ten days of the comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
45-day formal comment period with initial ballot	August 20 – October 5, 2015
45-day formal comment period with additional ballot	November 25, 2015 – January 8, 2016

Anticipated Actions	Date
10-day final ballot	March 2016
NERC Board (Board) adoption	May 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Planning Coordinator
     - **4.1.3.** RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
   - **4.2. Facilities:**
     - **4.2.1.** Remedial Action Schemes (RAS)
5. **Effective Date:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement; i.e., removal from service must be completed prior to implementation or retirement.

Functional modifications consist of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1 to the reviewing RC. In cases where a RAS crosses one or more RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review.

R1. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest-area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. Review by the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The RC may request assistance to perform

RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each submitted RAS. The time frame of four full calendar months is consistent with current utility and regional practice; however, flexibility is provided by allowing the RC(s) and RAS-entity(ies) to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in-service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the reviewing RC following identification of any reliability issue(s) is not necessary because the RAS-entity wants to expedite the timely approval and subsequent implementation of the RAS.

R3. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every sixty full calendar months. The purpose of the periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component failure or single component malfunction were to occur, the requirements for BES performance would continue to be satisfied. The

periodic evaluation is needed because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it impacts the BES. Requirement R4 also clarifies that the RAS single component failure and single component malfunction tests do not apply to RAS which are determined to be limited impact. A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented after the effective date of this standard will be designated as limited impact or not by the reviewing RC(s) during its review. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4. Requiring a limited impact RAS to meet the single component failure and single component malfunction tests would add complexity to the design with minimal benefit to the reliability of the BES. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator.

For existing RAS, the initial performance of Requirement R4 must be completed within sixty full calendar months of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within sixty full calendar months of the RAS approval date by the reviewing RC(s). Sixty full calendar months was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluation may involve modeling of the interconnected transmission system to assess BES performance. The Planning Coordinator (PC) is the functional entity best suited to perform this evaluation because they have a wide area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity.

The previous version of this standard (PRC-012-1 Requirement 1, R1.4) states "… the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the Contingency for which it was designed, and not exceed TPL-003-0." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise, consistent with PRC-012-1 Requirement 1, R1.4, the RAS should be designed so that its

whole or partial inadvertent operation due to a single component malfunction satisfies the System performance requirements for the same Contingency for which the RAS was designed.

If the RAS was installed for an extreme event in TPL-001-4 or for some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.1.3.1 – 4.1.3.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

R4. Each Planning Coordinator, at least once every 60 full calendar months, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.1.3. Except for "limited impact"[1] RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

4.1.3.1. The BES shall remain stable.

4.1.3.2. Cascading shall not occur.

4.1.3.3. Applicable Facility Ratings shall not be exceeded.

4.1.3.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

4.1.3.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

[1] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4.

4.1.4. Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: 1) verify RAS operation was consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. To promote reliability, each RAS-entity is required to provide the results of RAS operational performance analyses that identified any deficiencies to its reviewing RC(s).

RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate on the operational performance analysis.

R5. Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Participate in analyzing the RAS operational performance to determine whether:

5.1.1. The System events and/or conditions appropriately triggered the RAS.

5.1.2. The RAS responded as designed.

5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address.

5.1.4. The RAS operation resulted in any unintended or adverse BES response.

5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R5.

Rationale for Requirement R6: Deficiencies identified in the periodic RAS evaluation conducted by the PC pursuant to Requirement R4, in the operational performance analysis conducted by the RAS-entity pursuant to Requirement R5, or in the functional test performed by the RAS-entity pursuant to Requirement R8, potentially pose a reliability risk to the BES. To mitigate these potential reliability risks, Requirement R6 mandates that each RAS-entity develop a Corrective Action Plan (CAP) to address the identified deficiency. The CAP contains the mitigation actions and associated timetable necessary to remedy the specific deficiency. The RAS-entity may request assistance with CAP development from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

If the CAP requires that a functional change be made to a RAS, the RAS-entity will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in-service per Requirement R1.

Depending on the complexity of the identified deficiency(ies), development of a CAP may require studies, and other engineering or consulting work. A maximum time frame of six full calendar months is specified for RAS-entity collaboration on the CAP development.

R6. Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Being notified of a deficiency in its RAS pursuant to Requirement R4, or
- Notifying the Reliability Coordinator pursuant to Requirements R5, or
- Identifying a deficiency in its RAS pursuant to Requirement R8.

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.

Rationale for Requirement R7: Requirement R7 mandates each RAS-entity implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change, and when the CAP is completed.

R7. Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the reviewing Reliability Coordinator(s) that documents the implementation, updating, or completion of a CAP in accordance with Requirement R7.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005.

The six or twelve full calendar year test interval, which begins on the effective date of the standard pursuant to the PRC-012-2 implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by an undiscovered latent failure that could cause an incorrect operation or failure of the RAS. The RAS-entity is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. For

segmented testing, each segment of a RAS must be tested. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages.

The maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A correct operation of a RAS qualifies as a functional test for those RAS segments which operate (documentation for compliance with Requirement R5 Part 5.1). If an event causes a partial operation of a RAS, the segments without an operation will require a separate functional test within the maximum interval with the starting date determined by the previous successful test of the segments that did not operate.

R8. Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- At least once every six full calendar years for all RAS not designated as limited impact, or
- At least once every twelve full calendar years for all RAS designated as limited impact

M8. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entities identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review. The twelve full calendar month time frame is aligned with industry practice and allows sufficient time for the RC to collect the appropriate information from RAS-entities and update the RAS database.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was updated in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

The RAS-entity (Transmission Owner, Generator Owner, and Distribution Provider) shall each keep data or evidence to show compliance with Requirements R1, R3, R5, R6, R7, and R8, and Measures M1, M3, M5, M6, M7, and M8 since the last audit, 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 each keep data or evidence to show compliance with Requirements R2 and R9, and Measures M2 and M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator shall each keep data or evidence to show compliance with Requirement R4 and Measure M4 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a RAS-entity (Transmission Owner, Generator Owner or Distribution Provider), Reliability Coordinator, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.
R4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 60 full calendar months but less than or equal to 61 full calendar months.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 61 full calendar months but less than or equal to 62 full-calendar months.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 62 full calendar months but less than or equal to 63 full calendar months. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 63 full calendar months. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.4. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.
R5.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5.
R6.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.
R8.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		but less than or equal to 60 full calendar days.	but less than or equal to 90 full calendar days.	OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[2] RAS that the RAS-entity must document and provide to the reviewing Reliability Coordinator(s) (RC). If an item on this list does not apply to a specific RAS, a response of "Not Applicable" for that item is appropriate. When RAS are submitted for functional modification review and approval, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the existing functionality. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
4. Data to populate the RAS database:
    a. RAS name.
    b. Each RAS-entity and contact information.
    c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
    d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
    e. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
    f. Action(s) to be taken by the RAS.

[2] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

g. Identification of limited impact[3] RAS.

h. Any additional explanation relevant to high-level understanding of the RAS.

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy.
2. The action(s) to be taken by the RAS in response to disturbance conditions.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.
4. Information regarding any future System plans that will impact the RAS.
5. RAS-entity proposed designation as limited impact or not.
6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:
   a. The BES shall remain stable.
   b. Cascading shall not occur.
   c. Applicable Facility Ratings shall not be exceeded.
   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
7. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.
8. Identification of other affected RCs.

[3] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, control actions, logic processing, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS.
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in-service or is being maintained.
4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. The documentation should describe or illustrate how the design achieves this objective.
5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[4] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. If a checklist item is not relevant to a particular RAS, it should be noted as "Not Applicable." If reliability considerations are identified during the review, the considerations and the proposed resolutions should be documented with the remaining applicable Attachment 2 items.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.
2. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
3. The RAS avoids adverse interactions with other RAS, and protection and control systems.
4. The effects of RAS incorrect operation, including inadvertent operation and failure to operate, have been identified.
5. Determination whether or not the RAS is "limited impact.[5]" A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.
6. Except for limited impact RAS as determined by the RC, the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:
    a. The BES shall remain stable.
    b. Cascading shall not occur.
    c. Applicable Facility Ratings shall not be exceeded.

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[4] Functionally Modified: Any modification to a RAS consisting of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

[5] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

7. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).
2. The timing of RAS action(s) is appropriate to its BES performance objectives.
3. Except for limited impact RAS as determined by the RC, a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.
4. The RAS design facilitates periodic testing and maintenance.
5. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. Each RAS-entity and contact information.
3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
6. Action(s) to be taken by the RAS.
7. Identification of limited impact[6] RAS.
8. Any additional explanation relevant to high-level understanding of the RAS.

[6] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

Technical Justifications for Requirements

Applicability

4.1.1 Reliability Coordinator

The Reliability Coordinator (RC) is the best-suited functional entity to perform the Remedial Action Scheme (RAS) review because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The Wide-Area purview better facilitates the evaluation of interactions among separate RAS, as well as interactions among RAS and other protection and control systems. The selection of the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator, Transmission Planner, or other entities involved in the planning or implementation of a RAS. The RC is also less likely to be a stakeholder in any given RAS and can therefore maintain objective independence.

4.1.2 Planning Coordinator

The Planning Coordinator (PC) is the best-suited functional entity to perform the RAS evaluation to verify the continued effectiveness and coordination of the RAS, its inadvertent operation performance, and the performance for a single component failure. The items that must be addressed in the evaluations include: 1) RAS mitigation of the System condition(s) or event(s) for which it was designed; 2) RAS avoidance of adverse interactions with other RAS and with protection and control systems; 3) the impact of inadvertent operation; and 4) the impact of a single component failure. The evaluation of these items involves modeling and studying the interconnected transmission system, similar to the planning analyses performed by PCs.

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS (RAS components) have more than one owner, then each separate RAS component owner is a RAS-entity and is obligated to participate in various activities identified by the Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

Functional modifications consists of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

An example indicating the limits of an in-kind replacement of a RAS component is the replacement of one relay (or other device) with a relay (or other device) that uses similar functions. For instance, if a RAS included a CO-11 relay which was replaced by an IAC-53 relay, that would be an in-kind replacement. If the CO-11 relay were replaced by a microprocessor SEL-451 relay that used only the same functions as the original CO-11 relay, that would also be an in-kind replacement; however, if the SEL-451 relay was used to add new logic to what the CO-11 relay had provided, then the replacement relay would be a functional modification.

Changes to RAS pickup levels that require no other scheme changes are not considered a functional modification. For example, System conditions require a RAS to be armed when the combined flow on two lines exceeds 500 MW. If a periodic evaluation pursuant to Requirement R4, or other assessment, indicates that the arming level should be reduced to 450 MW without requiring any other RAS changes that would not be a functional modification. Similarly, if a RAS is designed to shed load to reduce loading on a particular line below 1000 amps, then a change in the load shedding trigger from 1000 amps to 1100 amps would not be a functional modification.

Another example illustrates a case where a System change may result in a RAS functional change. Assume that a generation center is connected to a load center through two transmission lines. The lines are not rated to accommodate full plant output if one line is out of service, so a RAS monitors the status of both lines and trips or ramps down the generation to a safe level following loss of either line. Later, one of the lines is tapped to serve additional load. The System that the RAS impacts now includes three lines, loss of any of which is likely to still require generation reduction. The modified RAS will need to monitor all three lines (add two line terminal status inputs to the RAS) and the logic to recognize the specific line outages would change, while the generation reduction (RAS output) requirement may or may not change, depending on which line is out of service. These required RAS changes would be a functional modification.

Any functional modification to a RAS will need to be reviewed and approved through the process described in Requirements R1, R2, and R3. The need for such functional modifications may be identified in several ways including but not limited to the Planning evaluations pursuant to R4, incorrect operations pursuant to R5, a test failure pursuant to R8, or Planning assessments related to future additions or modifications of other facilities.

To facilitate a review that promotes reliability, the RAS-entity(ies) must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity(ies) provide them to the reviewing Reliability Coordinator (RC). The RC that

coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity(ies) must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any reliability issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS-entity(ies). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among the RAS and other protection and control systems.

The selection of the RC also minimizes the possibility of a “conflict of interest” that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement. It is recognized that the RC does not possesses more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009.

Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each RAS submitted for review. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different

schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that each RAS-entity resolve all reliability issues (pertaining to its RAS) identified during the RAS review by the reviewing Reliability Coordinators. Examples of reliability issues include a lack of dependability, security, or coordination. RC approval of a RAS is considered to be obtained when the reviewing RC's feedback to each RAS-entity indicates that either no reliability issues were identified during the review or all identified reliability issues were resolved to the RC's satisfaction.

Dependability is a component of reliability that is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include "over-tripping" load or generation, or alternative automatic backup schemes.

Security is a component of reliability that is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-entity to effect a timely implementation.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every 60 full calendar months. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it interacts with and impacts the

BES. Requirement R4 also clarifies that the RAS single component failure and inadvertent operation tests do not apply to RAS which are determined to be limited impact. Requiring a limited impact RAS to meet the single component failure and inadvertent operation tests would just add complexity to the design with little or no improvement in the reliability of the BES.

For existing RAS, the initial performance of Requirement R4 must be completed within sixty full calendar months of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within sixty full calendar months of the RAS approval date by the reviewing RC(s). Sixty full calendar months was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.4) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The PC is the functional entity best suited to perform the analyses because they have a wide-area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each RAS-entity and reviewing RC, as well as each impacted Planning Coordinator and Transmission Planner.

The intent of Requirement R4, Part 4.1.3 is to require that the possible inadvertent operation of the RAS (other than limited impact RAS), caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event. The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented; otherwise, the RAS inadvertent operation must satisfy Requirement R4, Part 4.1.3.

The intent of Requirement R4, Part 4.1.3 is also to require that the possible inadvertent operation of the RAS (other than limited impact RAS) installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.1.3.1 – 4.1.3.5) are the ones that are common to all planning events (P0-P7) listed in TPL-001-4.

With reference to Requirement 4, Part 4.1.3, note that the only differences in performance requirements among the TPL (P0-P7) events (not common to all of them) concern Non-

Consequential Load Loss and interruption of Firm Transmission Service. It is not necessary for Requirement R4, Part 4.1.3 to specify performance requirements related to these areas because a RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

Part 4.1.4 requires that a single component failure in the RAS (other than limited impact RAS), when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

Requirements for inadvertent RAS operation (Requirement R4, Part 4.1.3) and single component failure (Requirement R4, Part 4.1.4) are reviewed by the reviewing RC(s) before a new or functionally modified RAS is placed in-service, and are typically satisfied by specific design considerations. Although the scope of the periodic evaluation does not include a new design review, it is possible that a design which previously satisfied requirements for inadvertent RAS operation and single component failure may fail to satisfy these requirements at a later time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, load growth could occur over time that impacts the amount of load to be tripped. These changes could result in tripping too much load upon inadvertent operation and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., “over trip”) in order to satisfy single component failure requirements. System changes could result in too little load being tripped and unacceptable BES performance if one of the loads failed to trip.

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation; however, flexibility is provided by allowing the parties to negotiate a different schedule for the analysis. To promote reliability, the RAS-entity(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s).

The RAS-entity(ies) may need to collaborate with its associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate on the operational performance analysis.

Requirement R6

RAS deficiencies potentially pose a reliability risk to the BES. RAS deficiencies may be identified in the periodic RAS evaluation conducted by the PC in Requirement R4, in the operational analysis conducted by the RAS-entity in Requirement R5, or in the functional test performed by the RAS-entity(ies) in Requirement R8. To mitigate potential reliability risks, Requirement R6 mandates that each RAS-entity participate in developing a CAP that establishes the mitigation actions and timetable necessary to address the deficiency.

The RAS-entity(ies) that owns the RAS components, is responsible for the RAS equipment, and is in the best position to develop the timelines and perform the necessary work to correct RAS deficiencies. If necessary, the RAS-entity(ies) may request assistance with development of the CAP from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

A CAP may require functional changes be made to a RAS. In this case, Attachment 1 information must be submitted to the reviewing RC(s), an RC review must be performed to obtain RC approval before the RAS-entity can place RAS modifications in-service, per Requirements R1, R2, and R3.

Depending on the complexity of the issues, development of a CAP may require study, engineering or consulting work. A timeframe of six full calendar months is allotted to allow enough time for RAS-entity collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. The possibility of such operating restrictions will incent the RAS-entity to resolve the issue as quickly as possible.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations or did not operate as designed.
- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.
- Functional testing identifies that a RAS is not operating as designed.

Requirement R7

Requirement R7 mandates that each RAS-entity implement its CAP developed in Requirement R6 which mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: “A list of actions and an associated timetable for implementation to remedy a specific problem.”

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the RAS-entity must notify the reviewing Reliability Coordinator(s). The RAS-entity must also notify the Reliability Coordinator(s) when the CAP has been completed.

The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed with minimum impact to the BES and should align with expected results. The RAS-entity is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-entity assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

The six and twelve full calendar year functional testing intervals are greater than the annual or bi-annual periodic testing performed in some NERC Regions. However, these intervals are a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Longer test intervals for limited impact RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the Bulk Power System.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is an acceptable method but may not be feasible for many RAS. When end-to-end testing is not possible, a RAS-entity may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end

scheme test, then the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing also includes the processing logic and infrastructure of a RAS as well as the action initiation by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within the applicable maximum test interval to demonstrate compliance with the Requirement.

As an example of segment testing, consider a RAS controller implemented using a PLC that receives System data, such as loading or line status, from distributed devices. These distributed devices could include meters, protective relays, or other PLCs. In this example RAS, a line protective relay is used to provide an analog metering quantity to the RAS control PLC. A functional test would verify that the System data is received from the protective relay by the PLC, processed by the PLC, and that PLC outputs are appropriate. There is no need to verify the protective relay's ability to measure the power system quantities, as this is a requirement for Protection Systems used as RAS in PRC-005, Table 1-1, Component Type – Protective Relay. Rather the functional test is focused on the use of the protective relay data at the PLC, including the communications data path from relay to PLC if this data is essential for proper RAS operation. Additionally, if the control signal back to the protective relay is also critical to the proper functioning of this example RAS, then that path is also verified up-to the protective relay. This example describes a test for one segment of a RAS which verifies RAS action, verifies PLC control logic, and verifies RAS communications.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.
>
> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of Contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The initial test interval begins on the effective date of the standard pursuant to the implementation plan. Subsequently, the maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A RAS-entity may choose to count a correct RAS operation as a qualifying functional test for those RAS segments which operate. If a System event causes a correct, but partial RAS operation, separate functional tests of the segments that did not operate are still required within the maximum test interval that started on the date of the previous successful test of those (non-operating) segments in order to be compliant with Requirement R8.

Requirement R9

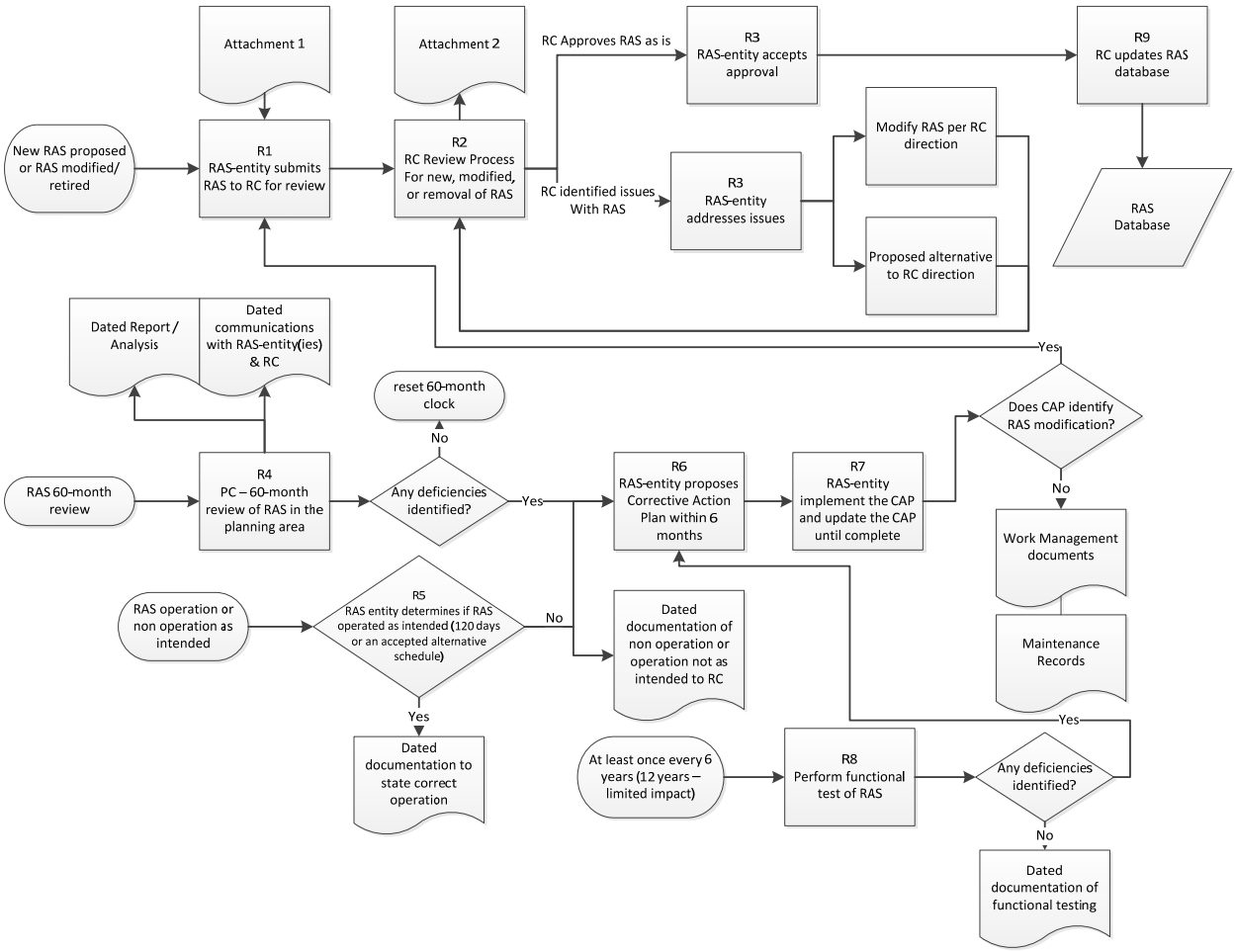
The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available to entities with a potential reliability need. Attachment 3 contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

Process Flow Diagram

The diagram below depicts the process flow of the PRC-012-2 requirements.



Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-entity(ies) to provide a detailed list of information describing the RAS to the reviewing RC. If there are multiple RAS-entities for a single RAS, information will be needed from all RAS-entities. Ideally, in such cases, a single RAS-entity will take the lead to compile all the data identified into a single Attachment 1.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[7] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the existing RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

[7] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, the analysis of an actual RAS operation pursuant to Requirement R5, or functional test failure pursuant to Requirement R8. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.

4. Initial data to populate the RAS database.
   a. RAS name
   b. Each RAS-entity and contact information
   c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60 full calendar month (Requirement R4) evaluation date; and, date of retirement, if applicable
   d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)
   e. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions)
   f. Corrective action taken by the RAS
   g. Identification of limited impact[8] RAS
   h. Any additional explanation relevant to high level understanding of the RAS

      Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]
   a. The System conditions that would result if no RAS action occurred should be identified.
   b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical System Contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

[8] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

c. Event-based RAS are triggered by specific Contingencies that initiate mitigating action. Condition-based RAS may also be initiated by specific Contingencies, but specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and when those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

5. RAS-entity proposed designation as "limited impact" or not.

   A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4.

6. Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]

   a. The BES shall remain stable.

   b. Cascading shall not occur.

c. Applicable Facility Ratings shall not be exceeded.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

7. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems.
[Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

   RAS are complex schemes that may take action such as tripping load or generation or re-configuring the System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.

8. Identification of other affected RCs.

   This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, logic processing, control actions, and monitoring.

Detection

Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

- Line open status (event detectors),
- Protective relay inputs and outputs (event and parameter detectors),
- Transducer and IED (analog) inputs (parameter and response detectors),
- Rate of change (parameter and response detectors).

DC Supply

Batteries and charges, or other forms of dc supply for RAS, are commonly also used for Protection Systems. This is acceptable, and maintenance of such supplies is covered by PRC-005. However, redundant RAS systems, when used, should be supplied from separately protected (fused or breakered) circuits.

Communications: Telecommunications Channels and Transfer Trip Equipment

Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-entity, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing

All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different Contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

Control Actions

RAS action devices may include a variety of equipment such as transfer trip, protective relays, and other control devices. These devices receive commands from the logic processing function (perhaps through telecommunication facilities) and initiate RAS actions at the sites where action is required.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in-service or out of service.
    - For RAS that are armed manually, the arming status may be the same as whether the RAS is in-service or out of service.
    - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in-service may be armed or unarmed based on whether the automatic arming criteria have been met.
- The current operational state of the scheme (available or not).

- In cases where the RAS requires single component failure performance; e.g., redundancy, the minimal status indications should be provided separately for each system.
  - The minimum status is generally sufficient for operational purposes; however, where possible it is often useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-entity to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Several methods to determine line or other equipment status are in common use, often in combination:

   a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; "a" contacts exactly emulate actual breaker status, while "b" contacts are opposite to the status of the breaker;

   b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;

   c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and

   d. Other detectors such as angle, voltage, power, frequency, rate of change of the aforementioned, out of step, etc. are dependent on specific scheme requirements, but some forms may substitute for or enhance other monitoring described in items 'a', 'b', and 'c' above.

   Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in-service or is being maintained.

   In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when

the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

a. Describe how the multifunction device is applied in the RAS.

b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

c. Describe the procedures used to isolate the RAS function from other functions in the device.

d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. The documentation should describe or illustrate how the design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement. Acceptable methods to achieve this objective include, but are not limited to the following:

   a. Providing redundancy of RAS components. Typical examples are listed below:

      i. Protective or auxiliary relays used by the RAS.

      ii. Communications systems necessary for correct operation of the RAS.

      iii. Sensing devices used to measure electrical or other quantities used by the RAS.

      iv. Station dc supply associated with RAS functions.

      v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

vi. Logic processing devices that accept System inputs from RAS components or other sources, make decisions based on those inputs, or initiate output signals to take remedial actions.

b. Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

c. Using alternative automatic actions to back up failures of single RAS components.

d. Manual backup operations, using planned System adjustments such as Transmission configuration changes and re-dispatch of generation, if such adjustments are executable within the time duration applicable to the Facility Ratings.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.

2. A summary of technical studies, if applicable, upon which the decision to retire the RAS is based.

3. Anticipated date of RAS retirement.

While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to facilitate consistent reviews continent-wide for new or functionally modified RAS prior to the RAS installation. The checklist is meant to assist the RC in identifying reliability-related considerations relevant to various aspects of RAS design and implementation.

Technical Justifications for Attachment 3 Content

Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
   - The name used to identify the RAS.
2. Each RAS-entity and contact information.
   - A reliable phone number or email address should be included to contact each RAS-entity if more information is needed.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60 full calendar month (Requirement R4) evaluation date; and, date of retirement, if applicable.
   - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
   - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).
   - A high level summary of the conditions/Contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
   - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.

7. Identification of limited impact[9] RAS.
    - Specify whether or not the RAS is designated as limited impact.
8. Any additional explanation relevant to high-level understanding of the RAS.
    - If deemed necessary, any additional information can be included in this section, but is not mandatory.

[9] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

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Implementation Plan for PRC-012-2

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Retirements

- PRC-012-1 – Remedial Action Scheme Review Procedure
- PRC-013-1 – Remedial Action Scheme Database
- PRC-014-1 – Remedial Action Scheme Assessment
- PRC-015-1 – Remedial Action Scheme Data and Documentation
- PRC-016-1 – Remedial Action Scheme Misoperations

Applicable Entities

- Reliability Coordinator
- Planning Coordinator
- RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS

Background

On November 13, 2014, the NERC Board of Trustees approved revisions to the definition for Remedial Action Scheme ("RAS") and associated revisions to related Reliability Standards to consolidate that term with the Glossary term "Special Protection System" (SPS).

In its February 3, 2015 petition to the Commission for approval of the definition of RAS and associated Reliability Standards ("Petition"), NERC noted that, although PRC-012-0, PRC-013-0, and PRC-014-0 were neither approved nor remanded by the Commission in Order No. 693 and were therefore not enforceable, NERC revised these standards to account for the RAS definition revision and changed relevant version numbers to reflect the change. Because of this change, NERC requested retirement of PRC-012-0, PRC-013-0, and PRC-014-0, and provided, for informational purposes only, updated Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1. In the same Petition, NERC requested retirement of PRC-015-0 and PRC-016-0.1 and approval of Reliability Standards PRC-015-1 and PRC-016-1, again implementing changes stemming from the revised definition of RAS.

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

Reliability Standard PRC-012-2 was developed to consolidate previously unapproved standards which were designated by the Commission as "fill-in-the-blank" standards and to revise other RAS-related standards. Reliability Standard PRC-012-2 also provides clear and unambiguous responsibilities to the specific users, owners, and operators of the Bulk-Power System. Reliability Standard PRC-012-2 establishes a new working framework between RAS-entities, PCs, and RCs, and this new framework will involve considerable start-up effort. As such, implementation of Reliability Standard PRC-012-2 will occur over a thirty six (36) month period after approval of the standard by applicable governmental authorities.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) 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. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

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 thirty six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Requirement R4

For existing RAS, initial performance of obligations under Requirement R4 must be completed within sixty (60) full calendar months of the effective date of PRC-012-2, as described above. For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within sixty (60) full calendar months of the date that the RAS is approved by the reviewing RC(s) under Requirement R3.

Requirement R8

For each RAS not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years of the effective date for PRC-012-2, as described above. For each RAS designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years of the effective date for PRC-012-2, as described above.

Requirement R9

For each Reliability Coordinator that does not have a RAS database upon the effective date of PRC-012-2, as described above, the initial obligation under Requirement R9 is to establish a database.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the effective date of PRC-012-2 in the particular jurisdiction in which the standard is becoming effective.

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Implementation Plan for PRC-012-2

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Retirements ~~of Reliability Standards~~[1]

- PRC-012-~~0 – Special Protection System~~1 – Remedial Action Scheme Review Procedure
- ~~PRC-013-0 – Special Protection System Database~~
- ~~PRC-014-0 – Special Protection System Assessment~~
- ~~PRC-012-1 – Special Protection System Review Procedure~~
- PRC-013-1 – ~~Special Protection System~~Remedial Action Scheme Database
- PRC-014-1 – ~~Special Protection System~~Remedial Action Scheme Assessment
- PRC-015-~~0 – Special Protection System~~1 – Remedial Action Scheme Data and Documentation
- PRC-016-~~0.~~1 – ~~Special Protection System~~Remedial Action Scheme Misoperations
- ~~PRC-015-1 – Special Protection System Data and Documentation~~
- ~~PRC-016-1 – Special Protection System Misoperations~~

~~Prerequisite Approval~~

- ~~Revised definition of "Remedial Action Scheme"~~

Applicable Entities

- Reliability Coordinator
- ~~Transmission Planner~~
- Planning Coordinator
- RAS-~~owner~~entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
- ~~RAS-entity – the RAS-owner designated to represent all RAS-owner(s) for coordinating the review and approval of a RAS~~

[1] ~~Retirement includes withdrawal of pending Reliability Standards.~~

~~General Considerations~~

Background

On November 13, 2014, the NERC Board of Trustees approved revisions to the definition for ~~RAS~~Remedial Action Scheme ("RAS") and associated revisions to related Reliability Standards to consolidate that term with the Glossary term "Special Protection System" (SPS).

In its February 3, 2015 petition to the Commission for approval of the definition of RAS and associated Reliability Standards ("Petition"), NERC noted that, although PRC-012-0, PRC-013-0, and PRC-014-0 were neither approved nor remanded by the Commission in Order No. 693 and were therefore not enforceable, NERC revised these standards to account for the RAS definition revision and changed relevant version numbers to reflect the change. ~~-~~Because of this change, NERC requested retirement of PRC-012-0, PRC-013-0, and PRC-014-0, and provided, for informational purposes only, updated Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1. ~~-~~In the same Petition, NERC requested retirement of PRC-015-0 and PRC-016-0.1 and approval of Reliability Standards PRC-015-1 and PRC-016-1 ~~and retirement of PRC-015-0 and PRC-016-0.1~~, again implementing changes stemming from the revised definition of RAS.

~~The~~On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to accept the revisions to the RAS definition and associated standards, and on ~~June 18, 2015. As of the date of posting of this Implementation Plan, however~~November 19, 2015, the Commission ~~has not~~ issued ~~an~~a Final Order approving the RAS definition and associated standards.

General Considerations

~~retirement the~~ Reliability ~~Standards enumerated above. Because~~Standard PRC-012-2 was developed to consolidate previously unapproved standards which were designated by the Commission as "fill-in-the-blank" standards and to revise other RAS-related standards. Reliability Standard PRC-012-2 also provides clear and unambiguous responsibilities to the specific users, owners, and operators of the Bulk-Power System. Reliability Standard PRC-012-2 establishes a new working framework between RAS-entities, PCs, and RCs, and this new framework will involve considerable start-up effort. As such, implementation of Reliability Standard PRC-012-2 will occur over a thirty six (36) month period after approval of the standard ~~drafting team for this project has determined that the retirements requested above are necessary to ensure a seamless transition to consolidation of these standards in PRC-012-2, NERC reiterates the requests for retirements already submitted in the Petition and those that are still pending at the Commission~~by applicable governmental authorities.

Effective ~~Dates for PRC-012-2~~Date

~~The proposed~~Where approval by an applicable governmental authority is required, Reliability Standard PRC-012-2 shall become effective on the ~~later of the day after the revised definition of Remedial Acton Scheme becomes effective or the~~ first day of the first calendar quarter that is ~~twelve (12~~thirty six (36) months after the ~~date~~effective date of the applicable governmental authority's order approving the

standard~~ is approved by an applicable governmental authority,~~ or as otherwise provided for ~~in a jurisdiction where approval~~ by ~~an~~the applicable governmental authority~~ is required for a standard to go into effect.~~ . Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

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 ~~twelve (12~~thirty six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Requirement R4

For existing RAS, initial performance of obligations under Requirement R4 must be completed within sixty (60) full calendar months of the effective date of PRC-012-2, as described above. For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within sixty (60) full calendar months of the date that the RAS is approved by the reviewing RC(s) under Requirement R3.

Requirement R8

For each RAS not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years of the effective date for PRC-012-2, as described above. For each RAS designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years of the effective date for PRC-012-2, as described above.

Requirement R9

For each Reliability Coordinator that does not have a RAS database upon the effective date of PRC-012-2, as described above, the initial obligation under Requirement R9 is to establish a database.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the ~~Effective Date~~effective date of PRC-012-2 in the particular jurisdiction in which the standard is becoming effective.

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Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: **R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review. **R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS. **R1.3.** Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.	**PRC-012-1 R.1.1**: Covered by Requirements R1, R2 and R3. **PRC-012-1 R.1.2**: Covered by Requirement R1, Attachment 1 **PRC-012-1 R.1.3**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4.1.4 **PRC-012-1 R.1.4**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4.1.3.	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. **R4.** Each Each Planning Coordinator, at least once every 60 full calendar months, shall:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0. **R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. **R1.6.** Regional Reliability Organization definition of misoperation. **R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations. **R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. **R1.9.** Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4.1.2. **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements R4 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.4 Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address.

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.4 The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R8.** Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: • At least once every six full calendar years for all RAS not designated as limited impact, or

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• At least once every twelve full calendar years for all RAS designated as limited impact
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information: **R1.1.** Design Objectives — Contingencies and system conditions for which the RAS was designed, **R1.2.** Operation — The actions taken by the RAS in response to Disturbance conditions, and	**PRC-013-1 R1**: Covered by Requirement R9 **PRC-013-1 R1.1, R1.2, R1.3:** Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months.

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.		
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each Each Planning Coordinator, at least once every 60 full calendar months, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.3 Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4** Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.2 Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	**PRC-014-1 R2**: Covered by Requirement R4	**R4.** Each Each Planning Coordinator, at least once every 60 full calendar months, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.3.4 BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4** Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements:	**PRC-014-1 R3**: Covered by Requirement R4	**R4.** Each Each Planning Coordinator, at least once every 60 full calendar months, shall:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R3.1. Identification of group conducting the assessment and the date the assessment was performed. **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed. **R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems. **R3.5.** Provide corrective action plans for non-compliant RAS.	**PRC-014-1 R3.1 - R3.4:** Covered by Requirement R4 **PRC-014-1 R3.5**: Covered by Requirement R6	**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.4 Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1.	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3.	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide	Retired P81	N/A

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).		

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7.	**R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	**PRC-016-1 R3**: Covered by Requirements R5, R6, and R7, Attachment 1.	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.2 The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		7.2 Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

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Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: **R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review. **R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS. **R1.3.** Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.	**PRC-012-1 R.1.1**: Covered by Requirements R1, R2 and R3. **PRC-012-1 R.1.2**: Covered by Requirement R1, Attachment 1 **PRC-012-1 R.1.3**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4.1.4 **PRC-012-1 R.1.4**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4.1.3.	**R1.** Prior to placing a new or functionally modified RAS in -service or retiring an existing RAS, each RAS-entity shall ~~submit~~provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) ~~that coordinates the area(s)~~ where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to ~~the~~each RAS-entity. **R3.** ~~Following the review performed pursuant to Requirement R2, the RAS entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator, prior~~Prior to placing a new or functionally modified RAS in--service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0. **R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. **R1.6.** Regional Reliability Organization definition of misoperation. **R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations. **R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. **R1.9.** Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4.1.2. **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements R4 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	R4. Each Each Planning Coordinator, at least once every 60 full calendar months, shall: **4.1** Perform~~R4. Each Transmission Planner shall perform~~ an evaluation of each RAS within its planning area ~~at least once every 60 full calendar months and provide the RAS owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall~~to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** ~~The~~ Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4** ~~A~~Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate~~,~~ does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R5.** Each RAS-~~owner shall~~entity, within 120~~-~~ full calendar days of a RAS operation or a failure of ~~a~~its RAS to operate when expected, ~~analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to~~or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s~~). The RAS~~), shall:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1 Participate in analyzing the RAS operational performance ~~analysis shall~~ to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. ~~**R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS owner~~**5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s~~,~~) within six full calendar months of: ~~**R8.** At least once every six calendar years, each~~• Being notified of a deficiency in its RAS ~~owner~~ pursuant to Requirement R4, or

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R8.** Each RAS-entity shall ~~perform~~participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components~~.~~: • At least once every six full calendar years for all RAS not designated as limited impact, or • At least once every twelve full calendar years for all RAS designated as limited impact
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information: **R1.1.** Design Objectives — Contingencies and system conditions for which the RAS was designed, **R1.2.** Operation — The actions taken by the RAS in response to Disturbance conditions, and **R1.3.** Modeling — Information on detection logic or relay settings that control operation of the RAS.	**PRC-013-1 R1**: Covered by Requirement R9 **PRC-013-1 R1.1**~~:~~ ~~Covered by Requirement R9, Attachment 3~~ ~~**PRC-013-1,** **R1.2**:~~ ~~Covered by Requirement R9, Attachment 3~~ ~~**PRC-013-1,** **R1.3:**~~ Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once ~~each~~every twelve full calendar ~~year~~months.
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each ~~Transmission Planner~~Each Planning Coordinator, at least once every 60 full calendar months, shall ~~perform~~: **4.1** Perform an evaluation of each RAS within its planning area ~~at least once every 60 full calendar months and provide the RAS owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall~~to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** ~~The~~Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4** ~~A~~Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate~~,~~ does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	**PRC-014-1 R2**: Covered by Requirement R4	**R4.** Each ~~Transmission Planner~~Each Planning Coordinator, at least once every 60 full calendar months, shall ~~perform~~: **4.1** Perform an evaluation of each RAS within its planning area ~~at least once every 60 full calendar months and provide the RAS owner(s) and the reviewing Reliability~~

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		~~Coordinator(s) the results including any identified deficiencies. Each evaluation shall~~to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** ~~The~~Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component ~~inadvertent operation~~malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		Transmission Planner and the Planning Coordinator. **4.1.4** ~~A~~Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate~~,~~ does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements: **R3.1.** Identification of group conducting the assessment and the date the assessment was performed. **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.	**PRC-014-1 ~~R2~~R3**: Covered by Requirement R4 **PRC-014-1 R3.1~~:~~** ~~Covered by Requirement R4~~ ~~**PRC-014-1 R3.2:**~~ ~~Covered by Requirement R4~~ ~~**PRC-014-1 R3.3:**~~ ~~Covered by Requirement R4~~	**R4.** Each ~~Transmission Planner~~Each Planning Coordinator, at least once every 60 full calendar months, shall ~~perform~~: **4.1** Perform an evaluation of each RAS within its planning area ~~at least once every 60 full calendar months and provide the RAS owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall~~to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R3.3. Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems. **R3.5.** Provide corrective action plans for non-compliant RAS.	~~**PRC-014-1** -~~ **R3.4:** Covered by Requirement R4 **PRC-014-1 R3.5**: Covered by Requirement R6	**4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** ~~The~~Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component ~~inadvertent operation~~ malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4** ~~A~~Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate~~,~~ does not prevent the BES from meeting the same performance requirements

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		(defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. ~~**R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS owner~~**4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s~~).~~) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1.	**R1.** Prior to placing a new or functionally modified RAS in -service or retiring an existing RAS, each RAS-entity shall ~~submit~~provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) ~~that coordinates the area(s)~~ where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3.	**R1.** Prior to placing a new or functionally modified RAS in -service or retiring an existing RAS, each RAS-entity shall ~~submit~~provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) ~~that coordinates the area(s)~~ where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to ~~the~~each RAS-entity. **R3.** ~~Following the review performed pursuant to Requirement R2, the RAS entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator, prior~~Prior to placing a new or functionally modified RAS in-~~-~~service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-~~owner shall~~entity, within 120~~-~~ full calendar days of a RAS operation or a failure of ~~a~~its RAS to operate when expected, ~~analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to~~or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s~~). The~~), shall: **5.1** Participate in analyzing the RAS operational performance ~~analysis shall~~ to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7.	~~**R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS owner~~**R6.** Each RAS-entity

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s~~).~~) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** ~~For~~Each RAS-entity shall, for each ~~CAP submitted~~of its CAPs developed pursuant to Requirement R6~~, each RAS-owner shall~~: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change~~.~~ and when the CAP is completed.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability	**PRC-016-1 R3**: Covered by Requirements R5, R6, and R7, Attachment 1.	**R5.** Each RAS-~~owner shall~~entity, within 120~~-~~ full calendar days of a RAS operation or a failure of ~~a~~its RAS to operate when expected, ~~analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to~~or on a mutually agreed upon

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
Organization and NERC on request (within 90 calendar days).		schedule with its reviewing Reliability Coordinator(s~~). The~~), shall: **5.1** Participate in analyzing the RAS operational performance ~~analysis shall~~ to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. ~~**R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS owner~~**5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s~~).~~) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** ~~For~~Each RAS-entity shall, for each ~~CAP submitted~~of its CAPs developed pursuant to Requirement R6~~, each RAS-owner shall~~: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change~~.~~ and when the CAP is completed.

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

Draft ~~1~~2 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, and PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS/SPS-related standards. ~~Draft 1~~This draft contains nine requirements and measures, the associated rationale boxes and corresponding technical guidelines. There are also three attachments within the draft standard that are incorporated via references in the requirements. ~~Draft 1of~~This draft of PRC-012-2 is posted for a 45-day ~~initial~~ formal comment period with a parallel ~~initial~~ ballot in the last ten days of the comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
45-day formal comment period with initial ballot	August 20 – October 5, 2015
45-day formal comment period with additional ballot	November 25, 2015 – January 8, 2016

Anticipated Actions	Date
10-day final ballot	~~December 2015~~March 2016
NERC Board (Board) adoption	~~February~~May 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   ~~4.1.2. Transmission Planner~~

   4.1.2. Planning Coordinator

   4.1.3. RAS-~~owner~~entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS

   ~~4.1.4. RAS-entity – the RAS-owner designated to represent all RAS-owner(s) for coordinating the review and approval of a RAS~~

   4.2. Facilities:

   4.2.1. Remedial Action Schemes (RAS)

5. **Effective Date:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement ~~(~~; i.e., removal from service~~)~~ must be completed prior to implementation or retirement. ~~A functional modification is~~

Functional modifications consist of any ~~modification~~of the following:

- Changes to ~~a RAS~~System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond ~~the~~in-kind replacement of existing components ~~that preserves the original functionality.~~
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1 to the reviewing RC. In cases where a RAS crosses one or more RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review.

R1. Prior to placing a new or functionally modified RAS in ~~-~~service or retiring an existing RAS, each RAS-entity shall ~~submit~~provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) ~~that coordinates the area(s)~~ where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest-area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview ~~provides continuity in the review process and~~ facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. ~~Including~~Review by the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC

is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The RC may request assistance ~~in~~to perform RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each ~~RAS~~ submitted RAS. The time frame of four~~-~~ full~~-~~ calendar months is consistent with current utility and regional practice; however, flexibility is provided by allowing the ~~parties~~RC(s) and RAS-entity(ies) to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1~~,~~ shall, within four~~-~~ full~~-~~ calendar months of receipt~~,~~ or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to ~~the~~each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in~~-~~service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the ~~RC review~~reviewing RC following identification of any reliability issue(s) is not necessary because ~~it is in~~ the RAS-~~entity's interest~~entity wants to ~~obtain an expeditious response from~~expedite the ~~entity and thus ensure a~~ timely approval and subsequent implementation~~.~~ of the RAS.

R3. ~~Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator prior~~Prior to placing a new or functionally modified RAS in~~-~~service or retiring an existing RAS~~.~~, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every sixty- full- calendar months. The purpose of ~~a~~the periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that ~~requirements for BES performance following an inadvertent~~, if a RAS ~~operation or a~~ single component failure ~~in the RAS continues~~or single component malfunction were to occur, the requirements for BES performance would continue to be satisfied. ~~A~~The periodic evaluation is needed because changes in ~~system~~System topology or operating conditions ~~that have occurred since the previous RAS evaluation or initial review was completed~~ may change the effectiveness of a RAS or the way it impacts the BES.

~~Sixty full calendar months,~~ Requirement R4 also clarifies that the RAS single component failure and single component malfunction tests do not apply to RAS which ~~begins on~~are determined to be limited impact. A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented after the effective date of ~~the~~this standard ~~pursuant to~~will be designated as limited impact or not by the ~~implementation plan,~~reviewing RC(s) during its review. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4. Requiring a limited impact RAS to meet the single component failure and single component malfunction tests would add complexity to the design with minimal benefit to the reliability of the BES. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator.

For existing RAS, the initial performance of Requirement R4 must be completed within sixty full calendar months of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within sixty full calendar months of the RAS approval date by the reviewing RC(s). Sixty full calendar months was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to ~~system~~System topology or ~~system~~System operating conditions ~~have occurred that~~ could potentially impact the effectiveness or coordination of the RAS. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluation ~~are planning analyses that~~may involve modeling of the interconnected transmission system to assess BES performance~~; consequently, the TP~~. The Planning Coordinator (PC) is the functional entity best suited to perform ~~the analyses.~~this evaluation because they have a wide area planning perspective. To promote reliability, the ~~TP~~PC is required to provide the ~~RAS owner(s) and each~~

~~reviewing RC with the~~ results of the evaluation~~.~~ to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity.

The previous version of this standard (PRC-012-~~0~~1 Requirement 1, R1.4) states "… the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the ~~contingency~~Contingency for which it was designed, and not exceed TPL-003-0." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise ~~and~~, consistent with PRC-012-~~0~~1 Requirement 1, R1.4, the RAS should be designed so that its whole or partial inadvertent operation due to a single component malfunction satisfies the ~~system~~System performance requirements for the same Contingency for which the RAS was designed.

If the RAS was installed for an extreme event in TPL-001-4 or for some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.1.3.1 – 4.1.3.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

R4. Each ~~Transmission Planner shall perform an evaluation of each RAS within its planning area~~ Planning Coordinator, at least once every 60~~-~~ full~~-~~ calendar~~-~~ months~~ and provide the RAS owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether:~~.~~, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

~~4.1.~~4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

~~4.2.~~4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

~~4.3.~~4.1.3. ~~The~~ Except for "limited impact"[1] RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

[1] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability

~~4.3.1.~~4.1.3.1. The BES shall remain stable.

~~4.3.2.~~4.1.3.2. Cascading shall not occur.

~~4.3.3.~~4.1.3.3. Applicable Facility Ratings shall not be exceeded.

~~4.3.4.~~4.1.3.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

~~4.3.5.~~4.1.3.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

~~4.4.~~4.1.4. ~~A~~Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate~~,~~ does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-~~owner(s)~~entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: 1) verify RAS operation ~~is~~was consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120~~-~~ full calendar~~-~~ day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. ~~-~~To promote

Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4.

reliability, each RAS-~~owner~~entity is required to provide the results of RAS operational performance analyses ~~to each~~that identified any deficiencies to its reviewing RC~~.~~(s).

RAS-~~owners~~entities may need to collaborate with their associated ~~TP~~Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation ~~triggers and responds (Parts~~was triggered correctly (Part 5.1~~,~~.1), responded as designed (Part 5.1.2~~)~~), and that the resulting BES response (Parts 5.1.3~~,~~ and 5.1.4) ~~is~~was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate on the operational performance analysis.

R5. Each RAS-~~owner shall~~entity, within 120~~-~~ full calendar days of a RAS operation or a failure of ~~a~~its RAS to operate when expected, ~~analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to~~or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s~~). The RAS operational performance analysis shall determine whether:~~), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Participate in analyzing the RAS operational performance to determine whether:

~~5.1.~~5.1.1. The System events and/or conditions appropriately triggered the RAS.

~~5.2.~~5.1.2. The RAS responded as designed.

~~5.3.~~5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address.

~~5.4.~~5.1.4. The RAS operation resulted in any unintended or adverse BES response.

5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R5.

Rationale for Requirement R6: Deficiencies~~,~~ identified ~~either~~ in the periodic RAS evaluation conducted by the ~~TP in~~PC pursuant to Requirement R4 ~~or~~, in the operational performance analysis conducted by the RAS-~~owner~~entity pursuant to Requirement R5, ~~are likely to~~or in the functional test performed by the RAS-entity pursuant to Requirement R8, potentially pose a reliability risk to the BES. To mitigate these potential reliability risks, Requirement R6 mandates that ~~the~~each RAS-~~owner~~entity develop a Corrective Action Plan (CAP) ~~that establishes~~to address the identified deficiency. The CAP contains the mitigation actions and associated timetable ~~to address the deficiency.~~ necessary to remedy the specific deficiency. The RAS-entity may request assistance with

CAP development from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

If the CAP requires that a functional change be made to a RAS, the RAS-~~owner~~entity will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in-~~-~~service per Requirement R1.

Depending on the complexity of the ~~issues,~~identified deficiency(ies), development of a CAP ~~might~~may require ~~study,~~studies, and other engineering~~,~~ or consulting work. A maximum time frame of six~~-~~ full~~-~~ calendar months is specified ~~to allow enough time~~ for RAS-~~owner~~entity collaboration on the CAP development~~, while ensuring that deficiencies are addressed in a reasonable time.~~ .

R6. ~~Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS owner~~Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s~~).~~) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Being notified of a deficiency in its RAS pursuant to Requirement R4, or
- Notifying the Reliability Coordinator pursuant to Requirements R5, or
- Identifying a deficiency in its RAS pursuant to Requirement R8.

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications ~~with~~among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.

Rationale for Requirement R7: Requirement R7 mandates ~~the~~each RAS-~~owner(s)~~entity implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4~~ and,~~ R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change~~.~~, and when the CAP is completed.

R7. ~~For~~Each RAS-entity shall, for each ~~CAP submitted~~of its CAPs developed pursuant to Requirement R6~~, each RAS owner shall~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the ~~appropriate~~reviewing Reliability Coordinator(s) that documents the implementation ~~or,~~ updating, or completion of a CAP in accordance with Requirement R7.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005. ~~The drafting team selected a six-calendar-year testing interval to be consistent with some of the maintenance intervals of various Protection System and Automatic Reclosing components established in PRC-005. This interval provides an entity the opportunity to design its RAS functional testing program such that it coincides with the testing of any associated PRC-005 components.~~

The six~~-~~ or twelve full calendar~~-~~ year test interval, which begins on the effective date of the standard pursuant to the PRC-012-2 implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by ~~a potentially~~an undiscovered latent failure that could cause an incorrect operation or failure of the RAS. The RAS-~~owner~~entity is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. ~~Each~~For segmented testing, each segment of a RAS ~~should~~must be tested ~~but overlapping~~. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages.

The maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A correct operation of a RAS qualifies as a functional test ~~as long as all~~for those RAS segments which operate~~.~~ (documentation for compliance with Requirement R5 Part 5.1). If an event causes a partial operation of a RAS, the segments without an operation will require a separate functional test within the ~~six year interval to be compliant with Requirement R8~~maximum interval with the starting date determined by the previous successful test of the segments that did not operate.

R8. ~~At least once every six calendar years, each~~Each RAS-~~owner~~entity shall ~~perform~~participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components~~:~~. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- At least once every six full calendar years for all RAS not designated as limited impact, or
- At least once every twelve full calendar years for all RAS designated as limited impact

M8. Acceptable evidence may include, but is not limited to, dated documentation ~~of~~detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional ~~testing~~test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that ~~can~~could potentially impact the ~~entities'~~ operational and/or planning activities of that entity. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-~~entity~~entities identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review. The twelve full calendar month time frame is aligned with industry practice and allows sufficient time for the RC to collect the appropriate information from RAS-entities and update the RAS database.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once ~~each~~every twelve full calendar ~~year~~months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was ~~maintained~~updated in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

The RAS-entity (Transmission Owner, Generator Owner, and Distribution Provider) shall each keep data or evidence to show compliance with Requirements R1 ~~through~~, R3, R5, R6, R7, and R8, and Measures M1, M3, M5, M6, M7, and M8 since the last audit, 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 each keep data or evidence to show compliance with Requirements R2 and R9, and Measures ~~M1 through~~M2 and M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator shall each keep data or evidence to show compliance with Requirement R4 and Measure M4 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a RAS-entity (Transmission Owner, Generator Owner or Distribution Provider), Reliability Coordinator, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to ~~submit~~provide the information identified in Attachment 1 to ~~one or more of the~~each Reliability Coordinator~~(s)~~ prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30~~-~~ full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30~~-~~ full calendar days but less than or equal to 60~~-~~ full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60~~-~~ full calendar days but less than or equal to 90~~-~~ full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90~~-~~ full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				accordance with Requirement R2.
R3.	N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R3.
R4.	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 60 full calendar months but less than or equal to 61 full calendar months.	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 61 full calendar months but less than or equal to 62 full calendar months.	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 62 full calendar months but less than or equal to 63 full calendar months. OR The ~~Transmission Planner~~Planning Coordinator performed the evaluation in	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 63 full calendar months. OR ~~The Transmission Planner failed to perform the evaluation in accordance with Requirement R4.~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.4.	~~OR~~ ~~The Transmission Planner~~The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.4. OR The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the ~~RAS owner(s) and the reviewing Reliability Coordinator(s).~~receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.	The RAS-~~owner~~entity performed the analysis in ~~greater than 120 calendar days, but less than or equal to 130 calendar days in~~ accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~130-~~10 full calendar days~~,~~ but less than or equal to ~~140-~~20 full calendar days ~~in accordance with Requirement R5~~.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~140-~~20 full calendar days~~,~~ but less than or equal to ~~150-~~30 full calendar days ~~in accordance with Requirement R5~~. OR The RAS-~~owner~~entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~150-~~30 full calendar days. OR ~~The RAS-owner failed to perform the analysis in accordance with Requirement R5.~~ ~~OR~~ ~~The RAS-owner~~The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4. OR The RAS-~~owner~~entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5.
R6.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10- full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10- full calendar days but less than or equal to 20- full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20- full calendar days but less than or equal to 30- full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30- full calendar days. OR The RAS-~~owner~~entity developed a Corrective Action Plan ~~and~~but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The RAS-~~owner~~entity failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-~~owner~~entity implemented a CAP ~~(~~in accordance with Requirement R7, Part 7.1~~),~~ but failed to update the CAP (Part 7.2) if actions or timetables changed ~~and~~, or failed to notify ~~one or more~~(Part 7.3) each of the reviewing Reliability Coordinator(s) ~~(Part 7.3), in accordance with Requirement R7~~of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-~~owner~~entity failed to implement a CAP ~~(Part 7.1)~~ in accordance with Requirement R7, Part 7.1.
R8.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days ~~late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days ~~late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days ~~late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days ~~late~~. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The RAS ~~owner~~entity failed to perform the functional test for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[2] RAS that the RAS-entity ~~shall~~must document and provide to the reviewing Reliability Coordinator(s) (RC~~) for review.~~). If an item on this list does not apply to a specific RAS, a response of ~~N/A or~~ "Not Applicable" for that item is appropriate. When ~~a~~ RAS ~~has been previously reviewed~~are submitted for functional modification review and approval, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the ~~previously approved~~existing functionality. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. ~~[Reference NERC Reliability Standard PRC-012, Requirements R5 and R7]~~
4. Data to populate the RAS database:
   a. RAS name.
   b. Each RAS-entity and contact information.
   c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
   d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
   e. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
   f. Action(s) to be taken by the RAS.

[2] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond ~~the~~in-kind replacement of existing components ~~that preserve the original functionality is a functional modification.~~
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

g. Identification of limited impact[3] RAS.

h. Any additional explanation relevant to high-level understanding of the RAS.

~~b.1.~~ **Functional** ~~RAS-entity and contact information.~~

~~c.1.Expected or actual in-service date; most recent RC approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.~~

~~d.1. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).~~

II. Description ~~of the contingencies or~~ and Transmission Planning Information

~~e.~~1. Contingencies and System conditions ~~for which~~that the RAS ~~was designed (i.e., initiating conditions).~~is intended to remedy.

2. The action(s) to be taken by the RAS in response to disturbance conditions.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.

4. Information regarding any future System plans that will impact the RAS.

5. RAS-entity proposed designation as limited impact or not.

6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:

   a. The BES shall remain stable.

   b. Cascading shall not occur.

   c. Applicable Facility Ratings shall not be exceeded.

   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

[3] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

7. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.

~~f. Action(s) to be taken by the RAS.~~

~~g.~~a.~~Any additional explanation relevant to high-level understanding of the RAS.~~

~~**II.I. Functional Description and Transmission Planning Information**~~

~~1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]~~

~~2.~~1. ~~The action(s) to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]~~

~~3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed. [Reference NERC Reliability Standard PRC-014, R3.2]~~

~~4.~~1. ~~Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]~~

~~1. Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]~~

~~a. The BES shall remain stable.~~

~~b.~~a. ~~Cascading shall not occur.~~

~~c.~~a. ~~Applicable Facility Ratings shall not be exceeded.~~

~~d.~~a. ~~BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.~~

~~e.~~a. ~~Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.~~

~~5.~~1. ~~An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems. [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]~~

~~6.~~8. Identification of other affected RCs.

III. Implementation

~~III.I.~~ ~~Implementation~~

1. Documentation describing the applicable equipment used for detection, ~~telecommunications~~dc supply, communications, transfer trip, control actions, logic processing, and monitoring.

~~2.~~ Information on detection logic and settings/parameters that control the operation of the RAS.~~Information on detection logic and settings/parameters that control the operation of the RAS.~~ ~~[Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]~~

2.

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.

4. Documentation ~~showing that~~describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. The documentation should describe or illustrate how the design achieves this objective.

~~4.1. , does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. The documentation should describe or illustrate how the design achieves this objective.~~
~~[Reference NERC Reliability Standard PRC-012, R1.3]~~

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[4] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any ~~reliability issue related to the RAS.~~aspect of the RAS as well as any reliability issue related to the RAS. If a checklist item is not relevant to a particular RAS, it should be noted as "Not Applicable." If reliability considerations are identified during the review, the considerations and the proposed resolutions should be documented with the remaining applicable Attachment 2 items.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.
2. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
3. The RAS avoids adverse interactions with other RAS, and protection and control systems.
4. The effects of RAS incorrect operation, including inadvertent operation and failure to operate ~~(if non-operation for RAS single component failure is acceptable),~~, have been identified.
5. ~~The~~Determination whether or not the RAS is "limited impact.[5]" A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

~~5.~~6. Except for limited impact RAS as determined by the RC, the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:

   a. The BES shall remain stable.

   b. Cascading shall not occur.

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[4] Functionally Modified:
Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond ~~the~~in-kind replacement of existing components ~~that preserve the original functionality is a functional modification.~~
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

[5] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

c. Applicable Facility Ratings shall not be exceeded.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

~~6.~~7. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).
2. The timing of RAS action(s) is appropriate to its BES performance objectives.

3. ~~A~~Except for limited impact RAS as determined by the RC, a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.
4. The RAS design facilitates periodic testing and maintenance.
5. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.

2. Each RAS-entity and contact information.

3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.

4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).

5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).

6. Action(s) to be taken by the RAS.

7. Identification of limited impact[6] RAS.

~~2.a.RAS-entity and contact information.~~

~~3.a.Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.~~

~~4.a.System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).~~

~~5.a.Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).~~

~~6.a.Action(s) to be taken by the RAS.~~

~~7.~~8. Any additional explanation relevant to high-level understanding of the RAS.

[6] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

Technical Justifications for Requirements

Applicability

4.1.~~4 RAS-~~1 Reliability Coordinator

The Reliability Coordinator (RC) is the best-suited functional entity to perform the Remedial Action Scheme (RAS) review because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The Wide-Area purview better facilitates the evaluation of interactions among separate RAS, as well as interactions among RAS and other protection and control systems. The selection of the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator, Transmission Planner, or other entities involved in the planning or implementation of a RAS. The RC is also less likely to be a stakeholder in any given RAS and can therefore maintain objective independence.

~~The purpose of the RAS-entity is to be the single information conduit with each reviewing Reliability Coordinator (RC) for all RAS-owners for each RAS. The RAS-entity needs to coordinate all review materials and any presentations. If all of the RAS equipment has a single owner, then the RAS-entity is the same as the RAS-owner and that owner speaks for itself.~~

4.1.2 Planning Coordinator

The Planning Coordinator (PC) is the best-suited functional entity to perform the RAS evaluation to verify the continued effectiveness and coordination of the RAS, its inadvertent operation performance, and the performance for a single component failure. The items that must be addressed in the evaluations include: 1) RAS mitigation of the System condition(s) or event(s) for which it was designed; 2) RAS avoidance of adverse interactions with other RAS and with protection and control systems; 3) the impact of inadvertent operation; and 4) the impact of a single component failure. The evaluation of these items involves modeling and studying the interconnected transmission system, similar to the planning analyses performed by PCs.

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS ~~equipment has~~(RAS components) have more than one owner, then each separate RAS ~~equipment owner is a RAS-owner. The RAS-entity will always be one of these RAS-owners. A RAS-entity will be selected by all RAS-owners and, traditionally, has usually been the owner of the RAS controller and a Transmission Owner. If a specific RAS-entity is not~~ component owner is a RAS-entity and is obligated to participate in various activities identified by the ~~RAS-owners, the RC will assign that function to the RAS-owner who provides the~~Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the

requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review ~~material to them~~process.

~~The RAS owner(s); i.e., Transmission Owner(s), Generator Owner(s), or Distribution Provider(s) who are not the RAS entity still have responsibilities as assigned in other NERC Reliability Standards, such as equipment maintenance. In addition, when RAS modifications are needed, each RAS owner of RAS equipment that must be modified must accept the specific responsibilities assigned to them as described in the necessary Corrective Action Plan (CAP), or otherwise as described in the revised Attachment 1.~~

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

~~Any modification~~Functional modifications consists of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond ~~the substitution~~in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

An example indicating the limits of an in-kind replacement of a RAS component is the replacement of one relay (or other device) with a relay (or other device) that ~~merely preserve~~ uses similar functions. For instance, if a RAS included a CO-11 relay which was replaced by an IAC-53 relay, that would be an in-kind replacement. If the CO-11 relay were replaced by a microprocessor SEL-451 relay that used only the same functions as the original ~~functionality is~~ CO-11 relay, that would also be an in-kind replacement; however, if the SEL-451 relay was used to add new logic to what the CO-11 relay had provided, then the replacement relay would be a functional modification.

Changes to RAS pickup levels that require no other scheme changes are not considered a functional modification. ~~Any~~For example, System conditions require a RAS to be armed when the combined flow on two lines exceeds 500 MW. If a periodic evaluation pursuant to Requirement R4, or other assessment, indicates that the arming level should be reduced to 450 MW without requiring any other RAS changes that would not be a functional modification. Similarly, if a RAS is designed to shed load to reduce loading on a particular line below 1000 amps, then a change in ~~RAS logic such as new~~ the load shedding trigger from 1000 amps to 1100 amps would not be a functional modification.

Another example illustrates a case where a System change may result in a RAS functional change. Assume that a generation center is connected to a load center through two transmission lines. The lines are not rated to accommodate full plant output if one line is out of service, so a RAS monitors the status of both lines and trips or ramps down the generation to a safe level following loss of either line. Later, one of the lines is tapped to serve additional load. The System that the RAS impacts now includes three lines, loss of any of which is likely to still require generation reduction. The modified RAS will need to monitor all three lines (add two line terminal status inputs ~~or outputs, or any other modification that affects overall RAS functionality, or redundancy level as documented in the original submission~~to the RAS) and the logic to recognize the specific line outages would change, while the generation reduction (RAS output) requirement may or may not change, depending on which line is out of service. These required RAS changes would be a functional modification.

Any functional modification to a RAS will need to be reviewed and approved through the process described in Requirements R1, R2, and R3. The need for ~~review are~~such functional ~~modifications. RAS~~ modifications may be identified ~~by a CAP pursuant to Requirement R6 beyond the substitution of components that merely preserve the original functionality are functional~~ in several ways including but not limited to the Planning evaluations pursuant to R4, incorrect operations pursuant to R5, a test failure pursuant to R8, or Planning assessments related to future additions or modifications~~. RAS removal is essentially a form of RAS functional modification. Any RAS proposed for removal needs to be evaluated under the RAS Retirement section of the Attachment 1 checklist.~~

of other facilities.

To facilitate a review that promotes reliability, the RAS-entity(ies) must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity(ies) provide them to the reviewing Reliability Coordinator (RC). The RC that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity(ies) must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any reliability issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-~~owner~~entity to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. ~~-~~A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS~~-owner(s).~~ entity(ies). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview ~~provides continuity in the review process and~~ facilitates the evaluation of interactions among separate RAS as well as interactions among the RAS and other protection and control systems.

The selection of the RC also minimizes the possibility of a "conflict of interest" that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement.

It is recognized that the RC does not possesses more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each RAS submitted ~~RAS~~ for review. The time frame of four~~-~~ full~~-~~ calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that ~~the~~each RAS-entity ~~address~~resolve all reliability issues (pertaining to its RAS) identified ~~by the reviewing RC~~ during the RAS review~~, and obtain approval from the reviewing RC that the RAS implementation can proceed. The review by the RC is intended to identify reliability issues that must be resolved before the RAS can be put in service.~~ by the reviewing Reliability Coordinators. Examples of reliability issues include a lack of dependability, security, or coordination. RC approval of a RAS is considered to be obtained when the reviewing RC's feedback to each RAS-entity indicates that either no reliability issues were identified during the review or all identified reliability issues were resolved to the RC's satisfaction.

Dependability is a component of reliability ~~and~~that is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include "over-tripping" load or generation, or alternative automatic backup schemes.

Security is a component of reliability ~~and~~that is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. ~~-~~Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity ~~(and any other RAS owner)~~ or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-~~owner~~entity to effect a timely implementation.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every 60 full calendar months. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in ~~system~~System topology or operating conditions ~~that have occurred since the previous RAS evaluation (or initial review)~~ may change the effectiveness of a RAS or the way it interacts with and impacts the BES.

~~A period~~ Requirement R4 also clarifies that the RAS single component failure and inadvertent operation tests do not apply to RAS which are determined to be limited impact. Requiring a limited impact RAS to meet the single component failure and inadvertent operation tests would just add complexity to the design with little or no improvement in the reliability of the BES.

For existing RAS, the initial performance of Requirement R4 must be completed within sixty full calendar months of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within sixty full calendar months of the RAS approval date by the reviewing RC(s). Sixty full calendar months was selected as the maximum time frame between evaluations based on the time frames for similar requirements in ~~NERC~~ Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation ~~should~~can be performed sooner if it is determined that material changes to System topology or System operating conditions ~~that~~ could potentially impact the effectiveness or coordination of the RAS ~~have occurred since the previous RAS evaluation or will occur before the next scheduled evaluation.~~ The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.4) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance~~; consequently, the TP~~. The PC is the functional entity best suited to perform the analyses~~.~~ because they have a wide-area planning perspective. To promote reliability, the ~~TP~~PC is required to provide the ~~RAS owner(s) and the reviewing RC(s) with the~~ results of ~~each~~the evaluation~~.~~

to each RAS-entity and reviewing RC, as well as each impacted Planning Coordinator and Transmission Planner.

The intent of Requirement R4, Part 4.1.3 is to require that the possible inadvertent operation of the RAS~~,~~ (other than limited impact RAS), caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event.

The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented ~~or else~~; otherwise, the RAS inadvertent operation ~~satisfies~~must satisfy Requirement R4, Part 4.1.3.

The intent of Requirement R4, Part 4.1.3 is also to require that the possible inadvertent operation of the RAS (other than limited impact RAS) installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.1.3.1 – 4.1.3.5) are the ones that are common to all planning events (P0-P7) listed in TPL-001-4.

With reference to Requirement 4, Part 4.1.3, note that the only differences in performance requirements among the TPL (P0-P7) events (not common to all of them) concern Non-Consequential Load Loss and interruption of Firm Transmission Service. ~~Performance~~It is not necessary for Requirement R4, Part 4.1.3 to specify performance requirements ~~in~~related to these areas ~~are not relevant. A~~because a RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service ~~can do that only~~ if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

Part 4.1.4 requires that a single component failure in the RAS~~,~~ (other than limited impact RAS), when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

Requirements for inadvertent RAS operation (Requirement R4, Part 4.1.3) and single component failure (Requirement R4, Part 4.1.4) are reviewed by the reviewing RC(s) before a new or functionally modified RAS is placed in~~-~~service, and are typically satisfied by specific design considerations. Although the scope of the periodic evaluation does not include a new design review, it is possible that a design which previously satisfied requirements for

inadvertent RAS operation and single component failure may fail to satisfy these requirements at a later ~~point in~~ time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, ~~System changes~~load growth could occur over time that ~~impact~~impacts the amount of load ~~originally~~to be tripped ~~by a particular RAS output.~~. These changes could result in ~~inadvertent activation of that output, therefore,~~ tripping too much load upon inadvertent operation and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., "over trip") in order to satisfy single- component- failure requirements. -System changes could result in too little load being tripped ~~at affected locations and result in~~and unacceptable BES performance if one of the loads failed to trip.

~~Requirement R5~~

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120- full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation~~.~~; however, flexibility is provided by allowing the parties to negotiate a different schedule for the analysis. To promote reliability, the RAS-~~owner~~entity(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s).

The RAS-~~owner(s~~entity(ies) may need to collaborate with ~~their~~its associated ~~TP~~Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation ~~triggers and responds (Parts~~was triggered correctly (Part 5.1~~,~~.1), responded as designed (Part 5.1.2~~)~~), and that the resulting BES response (Parts 5.1.3~~,~~ and 5.1.4) ~~is~~was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate on the operational performance analysis.

Requirement R6

~~Deficiencies~~ RAS deficiencies potentially pose a reliability risk to the BES. RAS deficiencies may be identified ~~either~~ in the periodic RAS evaluation conducted by the ~~TP~~PC in Requirement R4, ~~or~~ in the operational analysis conducted by the RAS-~~owner(s) pursuant to~~ entity in Requirement R5, ~~are likely to pose a reliability risk to the BES.~~ or in the functional test performed by the RAS-entity(ies) in Requirement R8. To mitigate ~~this~~potential reliability ~~risk~~risks, Requirement R6 mandates that each RAS-~~owner develop~~ entity participate in developing a CAP that establishes the mitigation actions and timetable necessary to address the deficiency.

The RAS-entity(ies) that owns the RAS components, is responsible for the RAS equipment, and is in the best position to develop the timelines and perform the necessary work to correct RAS deficiencies. If necessary, the RAS-entity(ies) may request assistance with development of the CAP ~~requires that a~~from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

A CAP may require functional ~~change~~changes be made to a RAS. In this case, Attachment 1 information must be submitted to the reviewing RC(s~~) prior~~), an RC review must be performed to ~~placing~~obtain RC approval before the RAS-entity can place RAS modifications in~~-~~service, per ~~Requirement~~Requirements R1~~.~~

, R2, and R3.

Depending on the complexity of the issues, development of a CAP may require study, engineering~~,~~ or consulting work. A timeframe of six~~-~~ full~~-~~ calendar months is allotted to allow enough time for RAS-~~owner~~entity collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. ~~Such~~The possibility of such operating restrictions will incent the RAS-~~owner~~entity to resolve the issue as quickly as possible~~.~~

~~A CAP documents a RAS performance deficiency, the actions to correct the deficiency with identified tasks, and the time frame for completion~~.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations~~. The RAS~~ or did not operate as designed.
- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.
- Functional testing identifies that a RAS is not operating as designed.

Requirement R7

~~Implementation of a CAP ensures~~Requirement R7 mandates that each RAS~~-~~entity implement its CAP developed in Requirement R6 which mitigates the deficiencies ~~are corrected by following a documented timetable of~~ identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions~~. If necessary, the~~ and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. ~~Operating restrictions imposed by the RC~~ If the CAP is changed, the RAS-entity must notify the reviewing Reliability Coordinator(s). The RAS-entity must also ~~incents RAS owners to mitigate the issues and provide assurance that implementation is~~ notify the Reliability Coordinator(s) when the CAP has been completed.

The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed ~~without~~with minimum impact to the BES and should align with expected results. The RAS-~~owner~~entity is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-~~owner~~entity assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

~~While the~~

The six~~-~~ and twelve full calendar~~-~~ year functional testing ~~interval is~~intervals are greater than the annual or bi-annual periodic testing performed in some NERC Regions~~, the drafting team selected it because it is consistent with some of the maintenance intervals of various Protection System and Automatic Reclosing components established in PRC-005. Consequently, this interval provides entities the opportunity to design their RAS functional testing programs such that it coincides with the testing of any associated PRC-005 components. The six calendar year interval is~~. However, these intervals are a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS.

Longer test intervals for limited impact RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the Bulk Power System.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is an acceptable method but ~~it~~ may not be feasible for many RAS. When end-to-end testing is not possible, a RAS-~~owner~~entity may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end ~~system~~scheme test~~—the~~, then the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing also includes the processing ~~by the~~ logic and infrastructure of a RAS as well as the action initiation by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within ~~a six-calendar-year interval to demonstrate compliance with the Requirement.~~

~~As an example, consider a RAS implemented with one PLC that senses System conditions such as loading and line status from many locations. At one of these locations, a line protective relay (a component of a Protection System and included in the Protection System Maintenance Program (PSMP) of a RAS owner) receives commands from the RAS PLC and sends data over non-Protection System communications infrastructure to operate a breaker. A functional test would send signals of simulated System conditions to the PLC to initiate an operate command to the protective relay, thus operating its associated breaker. This action verifies RAS action, verifies PLC control logic, and verifies RAS communications from PLC to relay. To complete this portion of a functional test, application of external testing signals to the protective relay, verified at the PLC are necessary to confirm full functioning of the RAS segment being tested. This example describes a test for one segment of the RAS, the remaining segments would also require testing~~the applicable maximum test interval to demonstrate compliance with the Requirement.

As an example of segment testing, consider a RAS controller implemented using a PLC that receives System data, such as loading or line status, from distributed devices. These distributed devices could include meters, protective relays, or other PLCs. In this example RAS, a line protective relay is used to provide an analog metering quantity to the RAS control PLC. A functional test would verify that the System data is received from the protective relay by the PLC, processed by the PLC, and that PLC outputs are appropriate. There is no need to verify the protective relay's ability to measure the power system quantities, as this is a requirement for Protection Systems used as RAS in PRC-005, Table 1-1, Component Type – Protective Relay. Rather the functional test is focused on the use of the protective relay data at the PLC, including the communications data path from relay to PLC if this data is essential for proper RAS operation. Additionally, if the control signal back to the protective relay is also critical to the proper functioning of this example RAS, then that path is also verified up-to the protective

relay. This example describes a test for one segment of a RAS which verifies RAS action, verifies PLC control logic, and verifies RAS communications.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. -The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.

> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of ~~contingencies~~Contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-~~2, Requirement R5.~~3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The initial test interval begins on the effective date of the standard pursuant to the implementation plan. Subsequently, the maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A RAS-entity may choose to count a correct RAS operation as a qualifying functional test for those RAS segments which operate. If a System event causes a correct, but partial RAS operation, separate functional tests of the segments that did not operate are still required within the maximum test interval that started on the date of the previous successful test of those (non-operating) segments in order to be compliant with Requirement R8.

Requirement R9

The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available to entities with a potential reliability need. Attachment 3

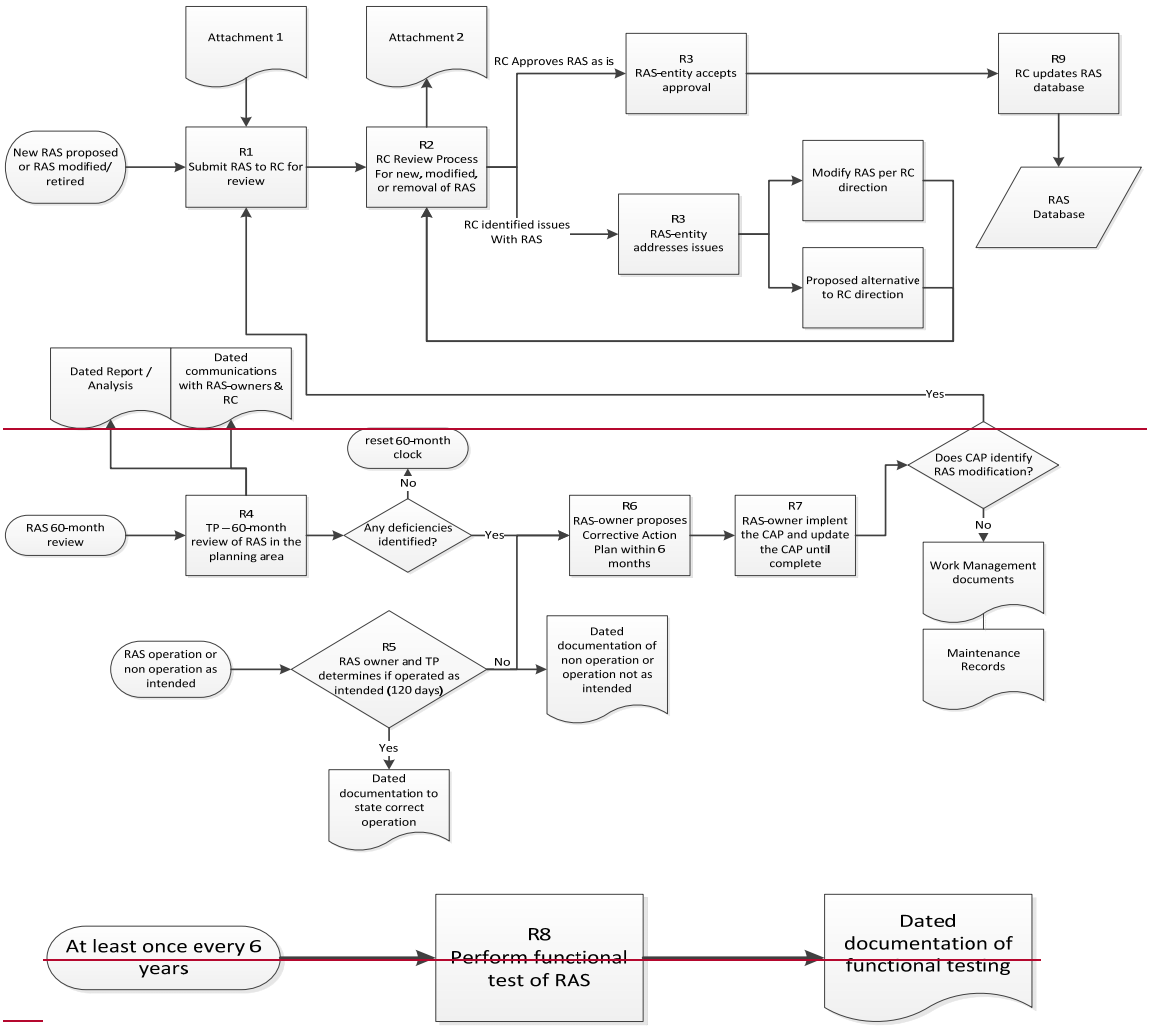
contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

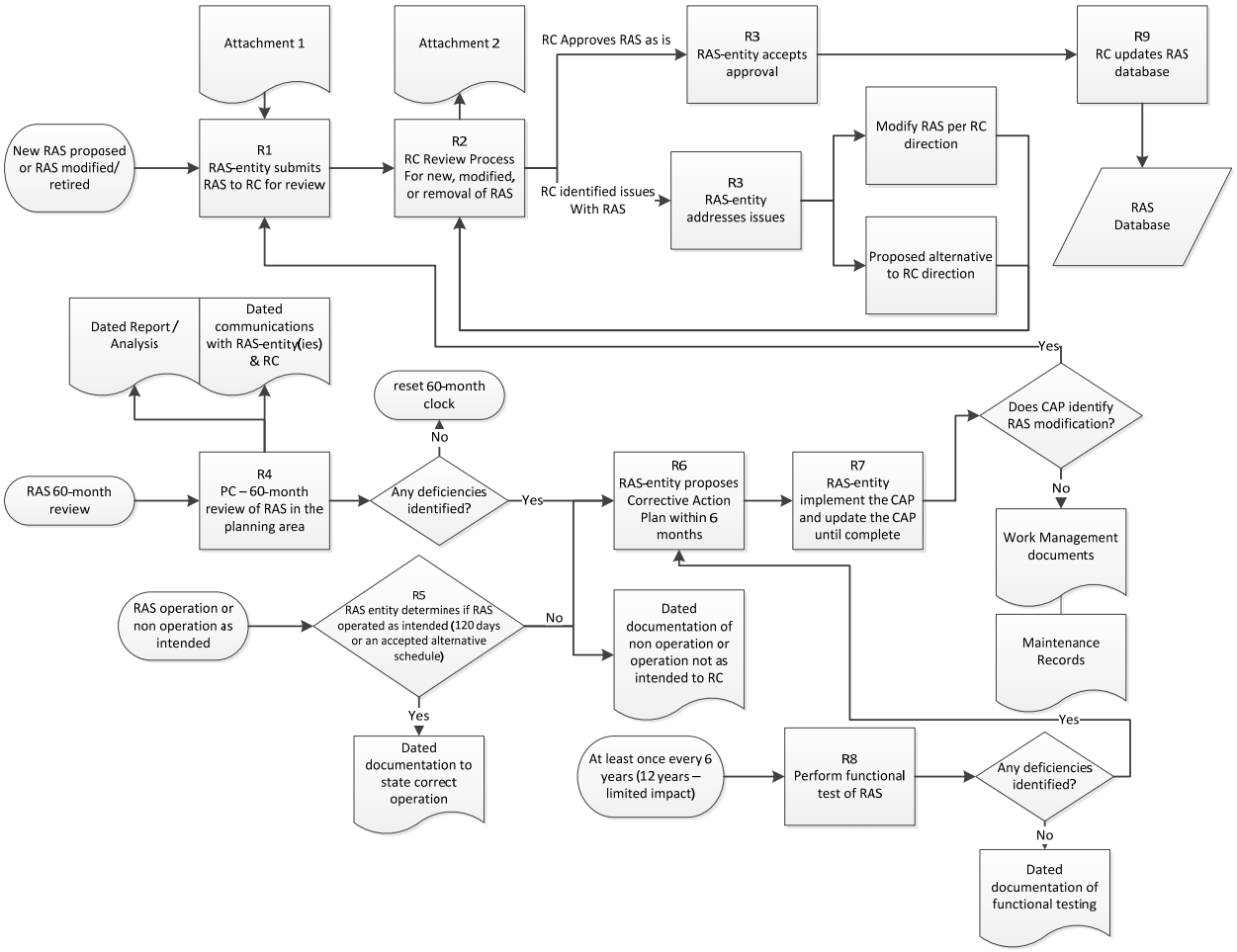
The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

Process Flow Diagram

The ~~following diagrams depict~~diagram below depicts the process flow of the PRC-012-2 requirements.




Attachment 1
Attachment 2
RC Approves RAS as is
R3
RAS-entity accepts approval
R9
RC updates RAS database
New RAS proposed or RAS modified/ retired
R1
RAS-entity submits RAS to RC for review
R2
RC Review Process For new, modified, or removal of RAS
RC identified issues With RAS
R3
RAS-entity addresses issues
Modify RAS per RC direction
Proposed alternative to RC direction
RAS Database
Dated Report / Analysis
Dated communications with RAS-entity(ies) & RC
Yes
reset 60-month clock
No
Does CAP identify RAS modification?
RAS 60-month review
R4
PC – 60-month review of RAS in the planning area
Any deficiencies identified?
Yes
R6
RAS-entity proposes Corrective Action Plan within 6 months
R7
RAS-entity implement the CAP and update the CAP until complete
No
Work Management documents
RAS operation or non operation as intended
R5
RAS entity determines if RAS operated as intended (120 days or an accepted alternative schedule)
No
Dated documentation of non operation or operation not as intended to RC
Maintenance Records
Yes
Yes
Dated documentation to state correct operation
At least once every 6 years (12 years – limited impact)
R8
Perform functional test of RAS
Any deficiencies identified?
No
Dated documentation of functional testing

Technical Justifications for Attachment 1 Content Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-~~owner(s~~entity(ies) to provide a detailed list of information describing the RAS to the ~~designated RAS-entity.~~reviewing RC. If there are multiple ~~owners of the~~RAS-entities for a single RAS, information ~~may~~will be needed from all ~~owners, but a single~~ RAS-~~owner (designated as the~~ entities. Ideally, in such cases, a single RAS-entity~~) is assigned~~ will take the ~~responsibility of compiling~~lead to compile all the ~~RAS~~ data ~~and presenting it to the reviewing RC(s). Other RAS owners may participate in the review, if they choose.~~ identified into a single Attachment 1.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[7] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the ~~previously approved~~existing RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the

[7] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond ~~the~~in-kind replacement of existing components ~~that preserve the original functionality is a functional modification.~~
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

   Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, ~~or~~ the analysis of an actual RAS operation pursuant to Requirement R5, or functional test failure pursuant to Requirement R8. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.

4. Initial data to populate the RAS database.

   a. RAS name

   b. Each RAS-entity and contact information

   c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60- full- calendar- month (Requirement R4) evaluation date; and, date of retirement, if applicable

   d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)

   e. Description of the ~~contingencies~~Contingencies or System conditions for which the RAS was designed (initiating conditions)

   f. Corrective action taken by the RAS

   g. Identification of limited impact[8] RAS

   ~~g.~~h. Any additional explanation relevant to high level understanding of the RAS

      Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

~~**II. Functional Description and Transmission Planning Information**~~

~~1. Contingencies and system conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]~~

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]

[8] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

a. The System conditions that would result if no RAS action occurred should be identified.

b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical ~~system contingencies~~System Contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

c. Event-based RAS are triggered by specific ~~contingencies~~Contingencies that initiate mitigating action. ~~-~~Condition-based RAS may also be initiated by specific ~~contingencies~~Contingencies, but specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. ~~-~~These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), ~~system~~System conditions, and ~~contingencies~~Contingencies analyzed on which the RAS design is based, and when those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. ~~-~~While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

~~4. Information regarding any future system plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]~~

4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

~~5. Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]~~

5. RAS-entity proposed designation as "limited impact" or not.

   A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4.

   ~~a. The BES shall remain stable.~~

   ~~b.~~a. ~~Cascading shall not occur.~~

   ~~c.~~a. ~~Applicable Facility Ratings shall not be exceeded.~~

~~d.a. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.~~

~~e.a. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.~~

6. Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]

   a. The BES shall remain stable.

   b. Cascading shall not occur.

   c. Applicable Facility Ratings shall not be exceeded.

   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

~~6.~~7. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems. [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

   RAS are complex schemes that may take action such as tripping load or generation or re-configuring the ~~system~~System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.

~~7.~~8. Identification of other affected RCs.

   This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, ~~telecommunications, transfer trip~~dc supply, communications, logic processing, control actions, and monitoring.

Detection

Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

- Line open status (event detectors),
- Protective relay inputs and outputs (event and parameter detectors),
- Transducer and IED (analog) inputs (parameter and response detectors),
- Rate of change (parameter and response detectors).

DC Supply

Batteries and charges, or other forms of dc supply for RAS, are commonly also used for Protection Systems. This is acceptable, and maintenance of such supplies is covered by PRC-005. However, redundant RAS systems, when used, should be supplied from separately protected (fused or breakered) circuits.

***Communications:* Telecommunications Channels and Transfer Trip Equipment**

Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-~~owner~~entity, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing

All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different ~~contingencies.~~ Contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to

existing RAS.

Control Actions

RAS action devices may include a variety of equipment such as transfer trip, protective relays, and other control devices. These devices receive commands from the logic processing function (perhaps through telecommunication facilities) and initiate RAS actions at the sites where action is required.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in-service or out of service.
  - For RAS that are armed manually, the arming status may be the same as whether the RAS is in-service or out of service.
  - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in-service may be armed or unarmed based on whether the automatic arming criteria have been met.
- The current operational state of the scheme (available or not).
- In cases where the RAS requires single- component failure performance (; e.g., redundancy), the minimal status indications should be provided separately for each system.
  - The minimum status is generally sufficient for operational purposes; however, where possible it may beis often useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-ownerentity to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Several methods to determine line or other equipment status are in common use, often in combination:

   a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; “a” contacts exactly emulate actual breaker status, while “b” contacts are opposite to the status of the breaker;

   b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;

   c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and

d. Other detectors such as angle, voltage, power, frequency, rate of change of ~~these~~the aforementioned, out of step, etc~~. — very~~. are dependent on specific scheme requirements, but some forms may substitute for or enhance ~~current~~other monitoring ~~detection~~described in items 'a', 'b', and 'c' above.

Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. ~~-~~These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in~~-~~service or is being maintained.

   In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

   a. Describe how the multifunction device is applied in the RAS.

   b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

   c. Describe the procedures used to isolate the RAS function from other functions in the device.

   d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

   e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

   f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

   g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

   Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation ~~showing that~~ describing the System performance resulting from a single~~-~~ component failure in ~~a~~the RAS, except for limited impact RAS, when the RAS is intended to operate~~, does~~. A single component failure in a RAS not determined to be limited impact must not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. The documentation should describe or illustrate how the ~~implementation~~ design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement. Acceptable methods to achieve this objective include, but are not limited to the following:

   ~~Acceptable methods to achieve this objective include the following:~~

   a. Providing redundancy of RAS components. Typical examples are listed below:

      i. Protective or auxiliary relays used by the RAS.

      ii. Communications systems necessary for correct operation of the RAS.

      iii. Sensing devices used to measure electrical or other quantities used by the RAS.

      iv. Station dc supply associated with RAS functions.

      v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

      ~~vi. Computers or programmable logic devices used to analyze information and provide RAS operational output.~~

      vi. Logic processing devices that accept System inputs from RAS components or other sources, make decisions based on those inputs, or initiate output signals to take remedial actions.

   b. Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation ~~would not be an issue, if~~due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

   c. Using alternative automatic actions to back up failures of single RAS components.

   d. Manual backup operations, using planned System adjustments such as Transmission configuration changes and re-dispatch of generation, if such adjustments are executable within the time duration applicable to the Facility Ratings.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of technical studies, if applicable, upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

   While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to facilitate consistent reviews continent-wide for new or functionally modified RAS prior to the RAS installation. The checklist is meant to assist the RC in identifying reliability-related considerations ~~generally~~ relevant to various aspects of RAS design and implementation~~, and also for the purpose of facilitating consistent reviews continent-wide for each RAS to be installed or functionally modified. Most of the checklist items should be applicable to most RAS. There may be checklist items that are not applicable to a given RAS in which case they may be noted as not applicable and skipped in the RC review. Depending on the specifics of the RAS under review, it is possible that other reliability considerations may be identified during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review~~.

Technical Justifications for Attachment 3 Content

Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
   - The name used to identify the RAS.
2. Each RAS-entity and contact information.
   - A reliable phone number or email address should be included to contact ~~the~~each RAS-entity if more information is needed~~. At a minimum, the name of the RAS-entity responsible for the RAS information should be provided~~.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60~~-~~ full~~-~~ calendar~~-~~ month (Requirement R4) evaluation date; and, date of retirement, if applicable.
   - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
   - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the ~~contingencies~~Contingencies or System conditions for which the RAS was designed (initiating conditions).
   - A high level summary of the conditions/~~contingencies~~Contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
   - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.
7. Identification of limited impact[9] RAS.
   - Specify whether or not the RAS is designated as limited impact.

~~7.~~8. Any additional explanation relevant to high-level understanding of the RAS.

[9] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

- If deemed necessary, any additional information can be included in this section, but is not mandatory.
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justification Document

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-012-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

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

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- 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

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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 PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) clearer criteria for operationally critical facilities. Requirement R1 mandates that entities comply with a review process for new or modified RAS or retirement of RAS. Among the elements of such reviews is the coordination between RAS and other RAS and between RAS and protection and control systems. Requirement R1 also mandates that the RAS-entity provide the Reliability Coordinator relevant RAS information regarding the design and implementation for each new or functionally modified RAS.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-012-1, Requirement 1, Parts R1.1 – R1.5 which specifies attributes of the RRO process to review RAS (R1.1), provision of pertinent RAS data (R1.2), dependability (R1.3) and security (R1.4) of design, and coordination with other RAS and protection systems (R1.5), and has a Medium VRF.
FERC VRF G4 Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
Guideline 4- Consistency with NERC Definitions of VRFs	service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-012-1, Requirements R1.1 – R1.5 which had four established Levels of Non-Compliance. The requirement is binary with only a Severe VSL so there is no consequence of lowering 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 language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS 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, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R2 relates to one of these areas, specifically, protection systems and their coordination. Requirement R2 mandates that Reliability Coordinators review the RAS to determine if a RAS avoids adverse interactions with other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-014-1, Requirement R1, which is related to the review of RAS.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS 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, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which also had four established Levels of Non-Compliance. This requirement has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering 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: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, 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 VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that 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, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R3 relates to one of these areas, specifically protection systems and their coordination. Requirement R3 requires the RAS-entity to address each identified reliability issue which includes the coordination between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-015-0 Requirement R2 which requires the entity to comply with the RRO procedure as defined in PRC-012-1 Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that 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, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-015-0, Requirement R2 which has four established VSLs. This requirement is binary with only a Severe VSL so there is no consequence of lowering 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 language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which 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. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R4 relates to one of these areas, specifically protection systems and their coordination. Requirement R4 mandates that entities perform periodic evaluations of each RAS to ensure that changes in System conditions have not changed the effectiveness of the RAS to mitigate the events or System conditions for which it was designed. Requirement R4 incorporates all actions necessary to determine if a RAS avoids adverse interactions with other RAS and protection and control systems
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R3 which requires the assessment of the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which 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. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 60 full calendar months but less than or equal to 61 full calendar months.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 61 full calendar months but less than or equal to 62 full-calendar months	The Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 62 full calendar months but less than or equal to 63 full calendar months. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 63 full calendar months. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.4. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
			receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which has four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R4	
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	

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which 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. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R5 relates to one of these areas, specifically protection systems and their coordination. Requirement R5 mandates that entities perform RAS operational performance analysis to verify that the RAS operation and the resulting System performance was consistent with the Contingency events or System conditions for which it was designed. Requirement R5 incorporates all actions necessary to identify coordination issues between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R4 which requires evaluation of the UVLS Program performance during a voltage excursion event.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which 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. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s).

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
			OR The RAS-entity failed to perform the analysis in accordance with Requirement R5

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0.1, Requirement R1, and PRC-012-1, Requirement R1.7, which have four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R5	
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	

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which 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, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R6 addresses one of these areas, specifically protection systems and their coordination. CAPs establish mitigation plans and timetable to address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which 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, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
			The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirements R2 and R3, and has VSLs comparable to the established Levels of Non-Compliance in those requirements, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R6	
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	

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which 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, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R7 relates to one of these areas, specifically protection systems and their coordination. Implemented CAPs address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which 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, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirement R2 and has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering 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: N/A Guideline 2b: The language included in the Lower and Severe VSLs is clear and unambiguous, 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 VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
NERC VRF Discussion	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly 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. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R8 has interactions in three of these areas, specifically (i) protection systems and their coordination, (ii) communication protocol and facilities, and (iii) appropriate use of transmission loading relief. RAS interactions occur with protection systems, utilize communication protocols and facilities for proper functioning, and are often used for transmission loading relief.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-3, Requirement R3 which requires the maintenance of Protection System Components and has a VRF of High.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly 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. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
mingle More than One Obligation	

VSLs for PRC-012-2, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days. OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-017-0, Requirements R1 and R2, which had VSLs of Lower, Moderate, High, and Severe. This requirement has VSLs comparable to the established VSLs so there is no consequence of lowering 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: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R9	
VRF for Requirement R9 is Lower	
NERC VRF Discussion	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, 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 VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R9 does not address any of the identified areas; therefore, the FERC VRF G1 Discussion is not applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with PRC-010-2 Requirement R6 and PRC-006-1 Requirement R6, which have an approved VRF of Lower.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, 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 VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-013-0, Requirement R1 and has VSLs comparable to the established Levels of Non-Compliance of that requirements, so there is no consequence of lowering the current level of compliance.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity 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: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, 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 VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations**FERC VSL G3** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is based upon a single violation, not a cumulative number of violations.The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justification Document

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-012-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

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

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- 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

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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 PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) clearer criteria for operationally critical facilities. Requirement R1 mandates that entities comply with a review process for new or modified RAS or retirement of RAS. Among the elements of such reviews is the coordination between RAS and other RAS and between RAS and protection and control systems. Requirement R1 also mandates that the RAS-entity provide the Reliability Coordinator relevant RAS information regarding the design and implementation for each new or functionally modified RAS.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-012-1, Requirement 1, Parts R1.1 – R1.5 which specifies attributes of the RRO process to review RAS (R1.1), provision of pertinent RAS data (R1.2), dependability (R1.3) and security (R1.4) of design, and coordination with other RAS and protection systems (R1.5), and has a Medium VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to ~~submit~~provide the information identified in Attachment 1 to ~~one or more of the~~each Reliability Coordinator~~(s)~~ prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-012-1, Requirements R1.1 – R1.5 which had four established Levels of Non-Compliance. The requirement is binary with only a Severe VSL so there is no consequence of lowering 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 language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS 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, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R2 relates to one of these areas, specifically, protection systems and their coordination. Requirement R2 mandates that Reliability Coordinators review the RAS to determine if a RAS avoids adverse interactions with other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-014-1, Requirement R1, which is related to the review of RAS.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS 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, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30- full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30- full calendar days but less than or equal to 60- full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60- full calendar days but less than or equal to 90- full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90- full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which also had four established Levels of Non-Compliance. This requirement has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering 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: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, 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 VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that 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, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R3 relates to one of these areas, specifically protection systems and their coordination. Requirement R3 requires the RAS-entity to address each identified reliability issue which includes the coordination between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-015-0 Requirement R2 which requires the entity to comply with the RRO procedure as defined in PRC-012-1 Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that 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, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-015-0, Requirement R2 which has four established VSLs. This requirement is binary with only a Severe VSL so there is no consequence of lowering 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 language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which 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. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R4 relates to one of these areas, specifically protection systems and their coordination. Requirement R4 mandates that entities perform periodic evaluations of each RAS to ensure that changes in System conditions have not changed the effectiveness of the RAS to mitigate the events or System conditions for which it was designed. Requirement R4 incorporates all actions necessary to determine if a RAS avoids adverse interactions with other RAS and protection and control systems
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R3 which requires the assessment of the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which 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. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 60~~-~~ full calendar months but less than or equal to 61~~-~~ full calendar months.	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 61~~-~~ full calendar months but less than or equal to 62~~-~~ full~~-~~calendar months~~.~~	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 62~~-~~ full calendar months but less than or equal to 63~~-~~ full calendar months. OR The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.4.	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 63~~-~~ full calendar months. OR ~~The Transmission Planner failed to perform the evaluation in accordance with Requirement R4.~~ ~~OR~~ ~~The Transmission Planner~~The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.4.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
			OR The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the ~~RAS owner(s) and the reviewing Reliability Coordinator(s).~~receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which has four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2	Guideline 2a: N/A

VSL Justifications for PRC-012-2, Requirement R4	
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 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which 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. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R5 relates to one of these areas, specifically protection systems and their coordination. Requirement R5 mandates that entities perform RAS operational performance analysis to verify that the RAS operation and the resulting System performance was consistent with the Contingency events or System conditions for which it was designed. Requirement R5 incorporates all actions necessary to identify coordination issues between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R4 which requires evaluation of the UVLS Program performance during a voltage excursion event.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which 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. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The RAS-~~owner~~entity performed the analysis in ~~greater than 120 calendar days, but less than or equal to 130 calendar days in~~ accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~130~~ 10 full calendar days~~,~~ but less than or equal to ~~140~~ 20 full calendar days ~~in accordance with Requirement R5~~.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~140~~ 20 full calendar days~~,~~ but less than or equal to ~~150~~ 30 full calendar days ~~in accordance with Requirement R5~~. OR The RAS-~~owner~~entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~150~~ 30 full calendar days. OR ~~The RAS-owner failed to perform the analysis in accordance with Requirement R5.~~ ~~OR~~ ~~The RAS-owner~~The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
			OR The RAS-~~owner~~entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0.1, Requirement R1, and PRC-012-1, Requirement R1.7, which have four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R5	
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	

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which 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, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R6 addresses one of these areas, specifically protection systems and their coordination. CAPs establish mitigation plans and timetable to address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which 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, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10~~-~~ full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10~~-~~ full calendar days but less than or equal to 20~~-~~ full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20~~-~~ full calendar days but less than or equal to 30~~-~~ full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30~~-~~ full calendar days. OR The RAS-~~owner~~entity developed a Corrective Action Plan ~~and~~but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
			The RAS-~~owner~~entity failed to develop a Corrective Action Plan in accordance with Requirement R6.

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirements R2 and R3, and has VSLs comparable to the established Levels of Non-Compliance in those requirements, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R6	
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	

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which 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, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R7 relates to one of these areas, specifically protection systems and their coordination. Implemented CAPs address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which 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, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The RAS-~~owner~~entity implemented a CAP ~~(~~in accordance with Requirement R7, Part 7.1~~),~~ but failed to update the CAP (Part 7.2) if actions or timetables changed ~~and~~, or failed to notify ~~one or more~~(Part 7.3) each of the reviewing Reliability Coordinator(s) ~~(Part 7.3), in accordance with Requirement R7~~of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-~~owner~~entity failed to implement a CAP ~~(Part 7.1)~~ in accordance with Requirement R7, Part 7.1.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirement R2 and has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering 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: N/A Guideline 2b: The language included in the Lower and Severe VSLs is clear and unambiguous, 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 VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
NERC VRF Discussion	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly 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. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R8 has interactions in three of these areas, specifically (i) protection systems and their coordination, (ii) communication protocol and facilities, and (iii) appropriate use of transmission loading relief. RAS interactions occur with protection systems, utilize communication protocols and facilities for proper functioning, and are often used for transmission loading relief.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-3, Requirement R3 which requires the maintenance of Protection System Components and has a VRF of High.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly 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. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
mingle More than One Obligation	

VSLs for PRC-012-2, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30- full calendar days~~ late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30- full calendar days but less than or equal to 60- full calendar days ~~late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60- full calendar days but less than or equal to 90- full calendar days ~~late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90- full calendar days~~ late~~. OR The RAS-~~owner~~entity failed to perform the functional test for a RAS as specified in Requirement R8.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-017-0, Requirements R1 and R2, which had VSLs of Lower, Moderate, High, and Severe. This requirement has VSLs comparable to the established VSLs so there is no consequence of lowering 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: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R9	
VRF for Requirement R9 is Lower	
NERC VRF Discussion	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, 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 VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R9 does not address any of the identified areas; therefore, the FERC VRF G1 Discussion is not applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with PRC-010-2 Requirement R6 and PRC-006-1 Requirement R6, which have an approved VRF of Lower.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, 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 VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30- full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30- full calendar days but less than or equal to 60- full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60- full calendar days but less than or equal to 90- full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90- full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-013-0, Requirement R1 and has VSLs comparable to the established Levels of Non-Compliance of that requirements, so there is no consequence of lowering the current level of compliance.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity 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: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, 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 VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations**FERC VSL G3** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is based upon a single violation, not a cumulative number of violations.The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

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Proposed Definition of "Special Protection System"

Special Protection System (SPS)

Background

In Order No. 693, the Commission approved, among other things, the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), which included NERC's currently definitions of Special Protection System and Remedial Action Scheme. The NERC Glossary currently defines a Special Protection System as:

> 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. An SPS 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 an SPS). Also called Remedial Action Scheme.

The currently-effective NERC Glossary definition for "Remedial Action Scheme" is a cross-reference to the definition of Special Protection System and reads: "See 'Special Protection System.'" This internal cross-references from Remedial Action Scheme to Special Protection System in lieu of a separate definition was developed to ensure that the terms are used interchangeably even where entities or an interconnection uses one term versus the other.

On February 3, 2015, NERC submitted a petition for approval of a revised definition of "Remedial Action Scheme" to add clarity and to ensure proper identification of Remedial Action Schemes and a more consistent application of related Reliability Standards. As explained in the petition, "[t]he defined terms 'Special Protection System' and 'Remedial Action Scheme' are currently used interchangeably throughout the NERC Regions and in various Reliability Standards, including prior versions of the Proposed Reliability Standards." Along with this proposed revised definition, NERC submitted revisions to various Reliability Standards by replacing the term "Special Protection System" and replacing it with the newly revised "Remedial Action Scheme." As NERC stated, "use of only one term in the NERC Reliability Standards will ensure proper identification of these systems and application of related Reliability Standards." The petition also anticipated future revision to the definition of "Special Protection System" to cross-reference the newly revised and proposed definition of "Remedial Action Scheme." This coordination, which would be achieved by implementing the new definition of "Special Protection System" simultaneously with the Commission approval of the revised definition for "Remedial Action Scheme," will ensure that all references to "Special Protection System" and "Remedial Action Scheme" refer to the same revised definition.

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to accept

the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

Proposed Definition

Special Protection System (SPS)

See “Remedial Action Scheme”

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Implementation Plan

Project 2010-14.2.1 Balancing Authority Reliability-based Controls Reliability Standard BAL-005-1

Requested Approval

- BAL-005-1 – Balancing Authority Controls

Requested Retirement

- BAL-005-0.2b – Automatic Generation Control

Prerequisite Approval

- FAC-001-3 – Facility Interconnection Requirements

Revisions to Glossary Terms

The following definitions shall become effective when BAL-005-1 becomes effective:

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): The addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$$\mathbf{I}_{ATEC} = \frac{\mathbf{PII}_{accum}^{on/off\ peak}}{(\mathbf{1}-\boldsymbol{Y})*\boldsymbol{H}}$$ when operating in Automatic Time Error Correction Mode.

The absolute value of $\mathbf{I_{ATEC}}$ shall not exceed L_{max} **.**

$\mathbf{I_{ATEC}}$ shall be zero when operating in any other AGC mode.

- L_{max} is the maximum value allowed for $\mathbf{I_{ATEC}}$ set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- $\boldsymbol{\varepsilon_{10}}$ is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- $\mathbf{B_i}$ = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B_i * ΔTE/6)
- II_{actual} is the hourly Inadvertent Interchange for the last hour.
  ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor,where: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection time monitor control center clocks.
- t is the number of minutes of manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$\mathbf{PII}_{accum}^{on/offpeak} = last\ period's\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

Reporting ACE is calculated as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Reporting ACE is calculated in the Western Interconnection as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where**:**

- NI_A = Actual Net Interchange.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,

4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' Reporting ACE equation (or alternate control processes).

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Applicable Entities

- Balancing Authority

Applicable Facilities

- N/A

Background

Reliability Standard BAL-005-1 addresses Balancing Authority Reliability-based Controls and establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). Reliability Standard BAL-005-1 (Balancing Authority Controls) and associated Implementation Plan was developed in conjunction with FAC-001-3 to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, FAC-001-3 will be implemented immediately after BAL-005-1 becomes effective as reflected in the Implementation Plan for FAC-001-3, and BAL-006-2 will be retired concurrently with the effective date for BAL-005-1 . Finally, to ensure proper coordination with BAL-001-2, approved by the Commission in Order No. 810 issued on April 16, 2015, the following definitions associated with BAL-005-1 will be implemented concurrently with the effective date for BAL-001-2:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

Effective Dates

Definitions

The definitions of the following terms shall become effective immediately after the effective date of BAL-001-2[1]:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

BAL-005-1

Where approval by an applicable governmental authority is required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months

[1] Because the definition of "Reporting ACE" associated with BAL-005-1 will become effective immediately after the effective date of BAL-001-2, the definition of "Reporting ACE" that was approved by the Commission on April 16, 2015 in Order No. 810 (151 FERC ¶ 61,048) will never go into effect.

after the effective date of the applicable governmental authorities order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Retirements

BAL-005-0.2b (Automatic Generation Control) shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

BAL-006-2 (Inadvertent Interchange) Requirement R3 shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

The existing definitions of Automatic Generation Control, Pseudo Tie and Balancing Authority shall be retired at midnight of the day immediately prior to the effective date of BAL-005-1, in the jurisdiction in which the new standard is becoming effective.

The existing definitions of Reporting ACE, Actual Frequency, Actual Net Interchange, Scheduled Net Interchange, Interchange Meter Error, and Automatic Time Error Correction shall be retired immediately after the effective date of BAL-001-2.[2]

[2] Note that the definition of Reporting ACE that was approved by the Commission in Order No. 810, which will replace the existing definition of Reporting ACE, will be retired immediately prior to the effective date for the revised definition of Reporting ACE, as described above. As such, the definition of Reporting ACE approved by the Commission in Order No. 810 will never go into effect.

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Implementation Plan

Project 2010-14.2.1 Balancing Authority Reliability-based Controls Reliability Standard BAL-005-1

Requested Approval

- BAL-005-1 – Balancing Authority Controls

Requested Retirement

- BAL-005-0.2b – Automatic Generation Control

Prerequisite Approval

- FAC-001-3 – Facility Interconnection Requirements

Revisions to Glossary Terms

The following definitions shall become effective when BAL-005-1 becomes effective:

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): The addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$$\mathbf{I}_{ATEC} = \frac{\mathbf{PII}_{accum}^{on/off\ peak}}{(\mathbf{1}-\mathbf{Y})*\mathbf{H}}$$ when operating in Automatic Time Error Correction Mode.

The absolute value of $\mathbf{I_{ATEC}}$ shall not exceed L_{max} **.**

$\mathbf{I_{ATEC}}$ shall be zero when operating in any other AGC mode.

- L_{max} is the maximum value allowed for $\mathbf{I_{ATEC}}$ set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10}\sqrt{(-10B_i)(-10B_S)}$.
- ~~ε_{10}~~ ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B_i * ΔTE/6)
- II_{actual} is the hourly Inadvertent Interchange for the last hour.
  ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor,where: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection time monitor control center clocks.
- t is the number of minutes of manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$\mathbf{PII}_{accum}^{on/offpeak} = last\ period's\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

Reporting ACE is calculated as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Reporting ACE is calculated in the Western Interconnection as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where**:**

- NI_A = Actual Net Interchange.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections ~~with multiple Balancing Authority Areas~~ operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,

4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards. ~~Centrally located equipment Equipment that automatically adjusts resources generation in a Balancing Authority Area from a central location to help maintain the Reporting ACE of a Balancing Authority's Area within the bounds required under the NERC Reliability Standardsinterchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction. Resources utilized under AGC may include, but not be limited to, conventional generation, variable energy resources, storage devices and loads acting as resources, such as Demand Response.~~

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' ~~control~~Reporting ACE equation (or alternate control processes).

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource~~load-interchange-generation~~ balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Applicable Entities

- Balancing Authority

Applicable Facilities

- N/A

Background

Reliability Standard BAL-005-1 addresses Balancing Authority Reliability-based Controls and establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). Reliability Standard BAL-005-1 (Balancing Authority Controls) and associated Implementation Plan was developed in conjunction with FAC-001-3 to ensure that entities with

facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, ~~BAL-005-1 **will implemented concurrently with**~~ FAC-001-3 will be implemented immediately after BAL-005-1 becomes effective~~,~~ as reflected in the Implementation Plan for FAC-001-3, and BAL-006-2 will be retired concurrently with the effective date for BAL-005-1 ~~"Prerequisite Approvals" section above~~. Finally, to ensure proper coordination with BAL-001-2, approved by the Commission in Order No. 810 issued on April 16, 2015, the following definitions associated with BAL-005-1 will be implemented concurrently with the effective date for BAL-001-2:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

Effective Dates

Definitions

The definitions of the following terms shall become effective immediately after the effective date of BAL-001-2[1]:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error

[1] Because the definition of "Reporting ACE" associated with BAL-005-1 will become effective immediately after the effective date of BAL-001-2, the definition of "Reporting ACE" that was approved by the Commission on April 16, 2015 in Order No. 810 (151 FERC ¶ 61,048) will never go into effect.

- Automatic Time Error Correction

BAL-005-1

Where approval by an applicable governmental authority is required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the ~~that this standard is approved by~~ applicable governmental ~~regulatory~~ authorities order approving the standard, or as otherwise provided for ~~in a jurisdiction where approval~~ by the ~~an~~ applicable governmental authority ~~is required for a standard to go into effect~~.

Where approval by an applicable governmental authority is not required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, ~~the standard~~ shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Retirements

BAL-005-0.2b (Automatic Generation Control) shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

BAL-006-2 (Inadvertent Interchange) Requirement R3 shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

The existing definitions of ~~Reporting ACE and~~ Automatic Generation Control, Pseudo Tie and Balancing Authority shall ~~should~~ be retired at midnight of the day immediately prior to the effective date of BAL-005-1, in the jurisdiction in which the new standard is becoming effective.

The existing definitions of Reporting ACE, Actual Frequency, Actual Net Interchange, Scheduled Net Interchange, Interchange Meter Error, and Automatic Time Error Correction shall be retired immediately after the effective date of BAL-001-2.[2]

[2] Note that the definition of Reporting ACE that was approved by the Commission in Order No. 810, which will replace the existing definition of Reporting ACE, will be retired immediately prior to the effective date for the revised definition of Reporting ACE, as described above. As such, the definition of Reporting ACE approved by the Commission in Order No. 810 will never go into effect.

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Implementation Plan

Reliability Standard BAL-006-2

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- N/A

Requested Retirement

- BAL-006-2 – Inadvertent Interchange

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Prerequisite Events

- NERC Operating Committee approval of Inadvertent Interchange Guideline[1]

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, BAL-006-2 will be retired concurrently with the effective date of BAL-005-1 and requisite approval of Inadvertent Interchange Guideline, as reflected in the "Prerequisite Approvals" and "Prerequisite Events" sections above.

Effective Dates

[1] Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

BAL-006-2 shall be retired on the effective date of BAL-005-1 and the approval of Inadvertent Interchange Guideline.

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Implementation Plan

Reliability Standard BAL-006-23

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- N/ABAL-006-3 – Inadvertent Interchange

Requested Retirement

- BAL-006-2 – Inadvertent Interchange

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Prerequisite Events

- NERC Operating Committee approval of Inadvertent Interchange Guideline[1]

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, BAL-006-23 will be retiredimplemented concurrently with the effective date of BAL-005-1 and requisite approval of Inadvertent Interchange Guideline, as reflected in the "Prerequisite Approvals" and "Prerequisite Events" sections above.

Effective Dates

[1] Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

BAL-006-23 shall become effective retired on the effective date of BAL-005-1 and the approval of Inadvertent Interchange Guideline.

Retirements

BAL-006-2 (Inadvertent Interchange) shall be retired immediately prior to the Effective Date of BAL-006-3 (Inadvertent Interchange) in the particular jurisdiction in which the revised standard is becoming effective.

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Violation Risk Factor and Violation Severity Level Assignments

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in BAL-005-1, Balancing Authority Control. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Frequency Response Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

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.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk Power System:[2]

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

Guideline (2) — Consistency within a Reliability Standard
The commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirement must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for BAL-005-1:
There are seven requirements in BAL-005-1. All of the requirements were assigned a "Medium" VRF.

VRF for BAL-005-1, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R3 and Requirement R5. This is also consistent with the current FERC approved VRF for BAL-005-0.2b Requirement R8.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is identical to the current enforceable BAL-005-0.2b Standard Requirement R8 which has an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, 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, but violation, in itself, would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.

- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-005-1, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF. This is also consistent with the current FERC approved VRF for BAL-005-0.2b Requirement R6.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is identical to the current enforceable BAL-005-0.2b standard Requirement R6 which has an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, 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, but violation, in itself, would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-005-1, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in BAL-005-1 are assigned a "Medium" VRF. This is also consistent with the current FERC approved VRF in BAL-005-0.2b Requirement R8.1.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-005-0.2b standard Requirement R8.1 which has an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, 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, but violation, in itself, would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-005-1, Requirement R4:

- FERC Guideline 2 — Consistency within a reliability standard exists. This requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-005-0.2b standard Requirement R8.1 which has an approved Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, 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, but violation, in itself, would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-005-1, Requirement R5:

- FERC Guideline 2 — Consistency within a reliability standard exists. This requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to BAL-005-0.2b standard Requirement R3 which has a Medium VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, 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, but violation, in itself, would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-005-1, Requirement R6:

- FERC Guideline 2 — Consistency within a reliability standard exists. This requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to BAL-005-0.2b standard Requirement R7 which has a Medium VRF.

- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, 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, but violation, in itself, would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for BAL-005-1, Requirement R7:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in BAL-005-1 are assigned a "Medium" VRF. This is also consistent with the current FERC approved VRF in BAL-005-0.2b Requirement R12 which has an approved Medium VRF and BAL-006-2 Requirement R3 which has a Lower VRF. However, the SDT felt that this requirement was not purely an administrative requirement and therefore deserved a higher VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-005-0.2b Requirement R12 which has an approved Medium VRF and BAL-006-2 Requirement R3 which has an approved Lower VRF. However, the SDT felt that this requirement was not purely an administrative requirement and therefore deserved a higher VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, 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, but violation, in itself, would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

Justification for Assignment of Violation Severity Levels:
In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL Guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in BAL-005-1 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 noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance 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 noncompliance 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.

VSLs for BAL-005-1 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 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 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	The NERC VSL Guidelines are satisfied. The requirement is binary and the performance measured does not meet the intent of the requirement.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. The proposed VSL language does not include ambiguous terms. The VSL is similar to the current approved VSL for BAL-005-0.2b Requirement R8.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VSLs for BAL-005-1 Requirement R2:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 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 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	The proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider the amount of time an entity is non-compliant with the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-005-1 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 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 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the amount of time an entity is non-compliant with the requirement.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-005-1 Requirement R4:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 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 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL Guidelines are satisfied. The requirement is binary and the performance measured does not meet the intent of the requirement.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on whether the information was provided.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-005-1 Requirement R5:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 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 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the amount of time an entity is non-compliant with the requirement.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-005-1 Requirement R6:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 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 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	The NERC VSL Guidelines are satisfied. The requirement is binary and the performance measured does not meet the intent of the requirement.	This requirement is new. As drafted, the proposed VSL does not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on whether the entity implemented an Operating Process to identify and mitigate errors.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-005-1 Requirement R7:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 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 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	The NERC VSL Guidelines are satisfied. The requirement is binary and the performance measured does not meet the intent of the requirement.	As drafted, the proposed VSL does not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in FAC-001-3, Facility Interconnection Requirements. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the base penalty amount regarding violations of requirements in FERC-approved reliability standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The Frequency Response Standard drafting team applied the following NERC criteria when proposing VRFs for the requirements under this project:

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.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The commission seeks to ensure that Violation Risk Factors assigned to requirements of reliability standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk Power System:[2]

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

Guideline (2) — Consistency within a Reliability Standard

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The commission expects a rational connection between the sub-requirement Violation Risk Factor assignments and the main requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards
The commission expects the assignment of Violation Risk Factors corresponding to requirements that address similar reliability goals in different reliability standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirement must not be watered down to reflect the lower risk level associated with the less important objective of the reliability standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's reliability standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance; and, therefore, concentrated its approach on the reliability impact of the requirements.

VRF for FAC-001-3:
There are four requirements in FAC-001-3. All of the requirements were assigned a "Lower" VRF.

VRF for FAC-001-3, Requirement R1:

There were no changes made to requirement R1. The current FERC approved VRFs are proposed to remain in effect.

VRF for FAC-001-3, Requirement R2:

There were no changes made to requirement R2. The current FERC approved VRFs are proposed to remain in effect.

VRF for FAC-001-3, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in FAC-001-3 are assigned a "Lower" VRF. This is also consistent with the current FERC approved VRF in FAC-001-2 Requirement R3.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable FAC-001-2 standard Requirement R3 which has an approved Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, 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, but violation, in itself, would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

VRF for FAC-001-3, Requirement R4:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in FAC-001-3 are assigned a "Lower" VRF. This is also consistent with the current FERC approved VRF in FAC-001-2 Requirement R4.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable FAC-001-2 standard Requirement R4 which has an approved Lower VRF.
- FERC Guideline 4 — Consistency with NERC's Definition of the VRF level selected exists. This requirement, 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, but violation, in itself, would unlikely result in the Bulk Electric System instability, separation, or cascading failures since this requirement is an after-the-fact calculation, not performed in Real-time.
- FERC Guideline 5 — This requirement does not co-mingle reliability objectives.

Justification for Assignment of Violation Severity Levels:
In developing the VSLs for the standards under this project, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL Guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in FAC-001-3 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 noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance 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 noncompliance 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.

VSLs for FAC-001-3 Requirement R1:

There were no changes made to requirement R1. The current FERC approved VSLs are proposed to remain in effect.

VSLs for FAC-001-3 Requirement R2:

There were no changes made to requirement R2. The current FERC approved VRFs are proposed to remain in effect.

VSLs for FAC-001-3 Requirement R3:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 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 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	As drafted, the proposed VSLs do not lower the current level of compliance. The proposed VSLs are similar to the current FERC approved VSLs in FAC-001-2 Requirement R3.	Proposed VSLs are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the number of parts the entity failed to address.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for FAC-001-3 Requirement R4:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 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 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	As drafted, the proposed VSLs do not lower the current level of compliance. The proposed VSLs are similar to the current FERC approved VSLs in FAC-001-2 Requirement R3.	Proposed VSL is binary and therefore only has a severe VSL. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the number of parts the entity failed to address.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

Standard Development Timeline

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

Description of Current Draft

This is the first posting of the draft standard for a 45-day formal comment period with an initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR Posted for comment	July 16, 2014
Standard posted for 45-day comment period and initial ballot	July 30, 2015

Anticipated Actions	Date
45-day formal comment period with additional ballot	November 2015 – January 2016
Final ballot	January 2016
NERC Board adoption	February 2016

New or Modified Terms 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.

Term:

Rationale for Modification of AGC: The original definition of AGC reflects "how to" control and automatically adjust equipment in a Balancing Authority Area and does not reflect the current technology nor the evolution of the industry from a “Control Area” to a “Balancing Area”. In addition, it was telling the entity "how to do it" rather than allowing the entity to perform the necessary functions in the most effective and reliable manner.

The new definition reflects a process and allows the entity the flexibility to perform the necessary function in the most effective and reliable manner to address such process without being instructed on "how to do it".

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Areas’ Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): The addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$$I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$$ when operating in Automatic Time Error Correction Mode.

The absolute value of I_{ATEC} shall not exceed L_{max} .

I_{ATEC} shall be zero when operating in any other AGC mode.

- L_{max} is the maximum value allowed for I_{ATEC} set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B_i * ΔTE/6)
- II_{actual} is the hourly Inadvertent Interchange for the last hour.
  ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor,where: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection time monitor control center clocks.
- t is the number of minutes of manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$PII_{accum}^{on/offpeak} = last\ period's\ PII_{accum}^{on/offpeak} + PII_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).
Reporting ACE is calculated as follows:

Reporting ACE = $(NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$

Reporting ACE is calculated in the Western Interconnection as follows:

Reporting ACE = $(NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} + I_{ATEC}$

Where**:**

- NI_A = Actual Net Interchange.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' Reporting ACE equation (or alternate control processes).

Rationale for Modification of Balancing Authority: The SDT has recommended to change the definition of Automatic Generation Control (AGC) and to be consistent, with the change to AGC, the SDT recommends changing the definition of a Balancing Authority. In addition, Project 2015-04 Alignment of Terms SDT brought to our attention of the inconsistent use of "load-interchange-generation" and through the Alignment of Terms project it was recommend a SDT associated with a BAL Standard address the issue. The proposed changes reflects a Balancing Authority.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the s*tandard.*

A. Introduction

1. **Title:** Balancing Authority Control
2. **Number:** BAL-005-1
3. **Purpose:** This standard establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). The standard also specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and for providing the information to the System Operator.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   Effective Date: See Implementation Plan for BAL-005-1

B. Requirements and Measures

Rationale for Requirement R1: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events, which would degrade the operator's ability to maintain reliability.

R1. The Balancing Authority shall use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R2: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC within 15

minutes thereafter so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

R2. A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

Rationale for Requirement R3: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. that is available a minimum of 99.95% for each calendar year; and,

3.2. with a minimum accuracy of 0.001 Hz.

M3. The Balancing Authority shall have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment used for the calculation of Reporting ACE had a minimum availability of 99.95% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R3.

Rationale for Requirement R4: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

R4. The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

Rationale for Requirement R5: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

R5. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M5. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R6: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

R6. Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M6. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R6 and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

Rationale for Requirement R7: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.

The intent of Requirement R7 Part 7.1 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the tie-line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example.

The intent of Requirement R7 Part 7.2 is to enable accuracy in the measurements and calculations used in Reporting ACE. It specifies the need for common metering points for hourly accumulated values for the time synchronized tie line MWh values agreed-upon between Balancing Authority Areas. These time synchronized agreed-upon values are necessary for use in the Operating Process required in R6 to identify and mitigate errors in the scan-rate values used in Reporting ACE.

R7. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

7.1. a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,

7.2. a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.

M7. The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to demonstratea common source for the components used in the calculation of Reporting ACE with its Adjacent Balancing Authority.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	Balancing Authority was using a design scan rate of greater than six seconds to acquire the data necessary to calculate Reporting ACE.
R2.	Real-time Operations	Medium	The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 50 minutes from the beginning of the	The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 55 minutes from the beginning of an	The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 60 minutes from the beginning of an	The Balancing Authority failed to notify its Reliability Coordinator within 60 minutes of the beginning of an inability to calculate Reporting ACE.

			inability to calculate Reporting ACE.	inability to calculate Reporting ACE.	inability to calculate Reporting ACE.	
R3.	Real-time Operations	Medium	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but was available greater than or equal to 99.94 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was available greater than or equal to 99.93 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but was available greater than or equal to 99.92 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.92% of the calendar year Or The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE failed to have a minimum accuracy of 0.001 Hz.
R4.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to make available information indicating missing or invalid data associated with

						Reporting ACE to its operators.
R5.	Operations Assessment	Medium	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.2% of the calendar year.
R6.	Same-day Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE.
R7.	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a common source for Tie-Lines, Pseudo-ties and Dynamic

						Schedules with its Adjacent Balancing Authorities **Or** **The Balancing Authority failed to use a time synchronized common source for hourly megawatt hour values that are agreed-upon to aid in the identification and mitigation of errors.**

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking

0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial	Errata
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0.1b	October 29, 2008	BOT approved errata changes; updated version number to "0.1b"	Errata
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Standards Attachments

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[Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material]

Rationale

Upon Board approval, the text from the rationale boxes will be moved to this section.

Standard Development Timeline

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

Description of Current Draft

This is the first posting of the draft standard for a 45-day formal comment period with an initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR Posted for comment	July 16, 2014
Standard posted for 45-day comment period and initial ballot	July 30, 2015

Anticipated Actions	Date
45-day formal comment period with additional ballot	November 2015 – January 2016
Final ballot	January 2016
NERC Board adoption	February 2016

New or Modified Terms 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.

Term:

Rationale for Modification of AGC: The original definition of AGC reflects "how to" control and automatically adjust equipment in a Balancing Authority Area and does not reflect the current technology nor the evolution of the industry from a "Control Area" to a "Balancing Area". In addition, it was telling the entity "how to do it" rather than allowing the entity to perform the necessary functions in the most effective and reliable manner.

The new definition reflects a process and allows the entity the flexibility to perform the necessary function in the most effective and reliable manner to address such process without being instructed on "how to do it".

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards. ~~Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.~~

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): The addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$$I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$$ when operating in Automatic Time Error Correction Mode.

The absolute value of I_{ATEC} shall not exceed L_{max} .

I_{ATEC} shall be zero when operating in any other AGC mode.

- L_{max} is the maximum value allowed for I_{ATEC} set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B_i * ΔTE/6)
- II_{actual} is the hourly Inadvertent Interchange for the last hour.
  ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor,where: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection time monitor control center clocks.
- t is the number of minutes of manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$PII_{accum}^{on/offpeak} = last\ period's\ PII_{accum}^{on/offpeak} + PII_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual

Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

Reporting ACE is calculated as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Reporting ACE is calculated in the Western Interconnection as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where**:**

- NI_A = Actual Net Interchange.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections ~~with multiple Balancing Authority Areas~~ operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' ~~control~~ Reporting ACE equation~~s~~ (or alternate control processes).

Rationale for Modification of Balancing Authority: The SDT has recommended to change the definition of Automatic Generation Control (AGC) and to be consistent, with the change to AGC, the SDT recommends changing the definition of a Balancing Authority. In addition, Project 2015-04 Alignment of Terms SDT brought to our attention of the inconsistent use of "load-interchange-generation" and through the Alignment of Terms project it was

recommend a SDT associated with a BAL Standard address the issue. The proposed changes reflects a Balancing Authority.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource~~load-interchange-generation~~ balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the s*tandard.*

A. Introduction

1. **Title:** Balancing Authority Control
2. **Number:** BAL-005-1
3. **Purpose:** This standard establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). The standard also specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and for providing the information to the System Operator.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

Effective Date: See Implementation Plan for BAL-005-1

B. Requirements and Measures

~~**Rationale for Requirement R1:** Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data (meaning data from the same source) is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.~~

~~The intent of Requirement R1 is to provide accuracy in the measurements and calculations used in Reporting ACE, hourly inadvertent energy, and Frequency Response measurements. It specifies the need for common metering points for instantaneous and hourly integrated values for the tie line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply when more than two Balancing Authorities participate in allocating shares of a generation resource or in supplementary regulation, for example.~~

~~**R1.** Each Balancing Authority shall ensure that each Tie Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with a mutually agreed-upon time-synchronized common source to determine hourly megawatt-hour values. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**1.1.** These values shall be exchanged between Adjacent Balancing Authorities.~~

~~**M1.** The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to determine if the Balancing Authority and its adjacent Balancing~~

~~Authority have agreed upon a time synchronized common source to determine megawatt-hour values.~~

Rationale for Requirement R12: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events, which would degrade the operator's ability to maintain reliability.

~~R2.~~R1. The Balancing Authority shall use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~M2.~~M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R23: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC within 15 minutes thereafter so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

~~R3.~~R2. A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of the~~an~~ inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~M3.~~M2. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of the~~an~~ inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

Rationale for Requirement R34: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

~~R4.~~R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~4.1.~~3.1. that is available a minimum of 99.95% for each calendar year; and,

~~4.2.~~3.2. with a minimum accuracy of 0.001 Hz.

~~M4.~~M3. The Balancing Authority shall have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment used for the calculation of Reporting ACE had a minimum availability of 99.95% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R3~~4~~.

Rationale for Requirement R~~4~~5: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

~~R5.~~R4. The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~M5.~~M4. Each Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

Rationale for Requirement R~~5~~6: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

~~R6.~~R5. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

~~M6.~~M5. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R6~~7~~: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

~~R7.~~R6. Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the ~~scan rate~~ accuracy of scan- rate data used in the calculation of Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

~~M7.~~M6. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R6~~7~~ and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

Rationale for Requirement R7~~8~~: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.

The intent of Requirement R7~~8~~ Part 7.1 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the tie-line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example.

The intent of Requirement R7 Part 7.2 is to enable accuracy in the measurements and calculations used in Reporting ACE. It specifies the need for common metering points for hourly accumulated values for the time synchronized tie line MWh values agreed-upon between Balancing Authority Areas. These time synchronized agreed-upon values are necessary for use in the Operating Process required in R6 to identify and mitigate errors

in the scan-rate values used in Reporting ACE.

R7. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with:~~Each Balancing Authority shall agree with an Adjacent Balancing Authority on a common source for respective Tie-Lines, Pseudo-Ties, and Dynamic Schedules and shall implement that common source to provide common information to both Balancing Authorities for the calculation of Reporting ACE.~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

7.1. a ~~mutually agreed-upon~~ common source to provide ~~common~~ information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,

7.2. a ~~mutually agreed-upon~~ time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.

~~**M8.**~~**M7.** The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to demonstrate~~determine if it agreed with its adjacent Balancing Authority on a~~ common source for the components used in the calculation of Reporting ACE with its Adjacent Balancing Authority.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R1.~~	~~Operations Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to agree upon a time synchronized common source for hourly megawatt hour values with its Adjacent Balancing Authorities~~ ~~Or~~ ~~The Balancing Authority failed to provide the megawatt hour values to its Adjacent Balancing Authorities.~~
R1~~2~~.	Real-time Operations	Medium	N/A	N/A	N/A	Balancing Authority was using a design scan rate of greater than six seconds to acquire the data necessary to

						calculate Reporting ACE.
R23.	Real-time Operations	Medium	The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of thean inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 50 minutes from the beginning of thean inability to calculate Reporting ACE.	The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 55 minutes from the beginning of an inability to calculate Reporting ACE.	The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 60 minutes from the beginning of an inability to calculate Reporting ACE.	The Balancing Authority failed to notify its Reliability Coordinator within 60 minutes of the beginning of an inability to calculate Reporting ACE.
R34.	Real-time Operations	Medium	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but was available greater than or equal to	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was available greater than or equal to	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but was available greater than or equal to	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.92% of the calendar year Or The Balancing Authority's frequency

			99.94 % of the calendar year.	99.93 % of the calendar year.	99.92 % of the calendar year.	metering equipment used for the calculation of Reporting ACE failed to have a minimum accuracy of 0.001 Hz.
R45.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to make available information indicating missing or invalid data associated with Reporting ACE to its operators.
R56.	Operations Assessment	Medium	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.2% of the calendar year.

R6~~7~~.	Same-day Operations	Medium	N/A	N/A	N/A	The Balancing A~~a~~uthority failed to implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE.
R7~~8~~.	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to use~~agree upon~~ a common source for ~~t~~Tie-~~l~~Lines, Pseudo-ties and Dynamic Schedules with its Adjacent Balancing Authorities Or ~~The Balancing Authority failed to implement the common source to provide common information to both Balancing Authorities.~~

						~~Or~~ -The Balancing Authority failed to use~~agree upon~~ a time synchronized common source for hourly megawatt hour values that are agreed-upon to aid in the identification and mitigation of errors.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New

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Rationale

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2010-14.2.1 Mapping Document
Transition of BAL-005-0.2b to BAL-005-1

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-1 R1	Requirement R1 Part R1.1 and Part R1.2 have been moved into FAC-001-2 Requirement R3 and R4. Requirement R1 Part R1.3 is being retired.	Requirements R1 Parts R1.1 and R1.2 do not provide for necessary information concerning the calculation of Reporting ACE. The requirement provides for information necessary when connecting to the electric system. Requirement R1 Part 1.3 is being retired in conjunction with the Risk-based Registration initiative de-certifying the LSE function.
BAL-005-0.2b R2	Retired	This requirement was retired as part of the original Paragraph 81 project. Its retirement was approved by FERC effective January 21, 2014.
BAL-005-0.2b R3	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7.
BAL-005-0.2b R4	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7.
BAL-005-0.2b R5	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R6	Moved to definition of Reporting ACE and Requirement R2	The portion of the requirement concerning calculating ACE was moved into the definition for Reporting ACE. The portion of the requirement concerning an entity's inability to calculate Ace for more than 30 minutes was moved into Requirement R2.
BAL-005-0.2b R7	Retire	This requirement should be retired under Paragraph 81 criteria. The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, though resources can be dispatched manually without any detriment to reliability. The SDT believes that the term "operate AGC" in R7 refers to the capability to continuously calculate ACE, not automatic control of resources to the extent BAs cannot take resources off "AGC" mode.
BAL-005-0.2b R8	The body of this requirement was moved to Requirement R1 and Part 8.1 was moved into Requirement R3	The body of this requirement has been moved to Requirement R1 and Part 8.1 has been moved into Requirement R3.
BAL-005-0.2b R9	Retire	R9 is covered in the definition of Reporting ACE, and the proposed R7 ensures that the BA does not include any Interchange in its Reporting ACE that does not have an Adjacent BA. Regarding R9.1, the Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the Balancing Authority is not being instructed "how" to implement the HVDC link, but allowed to decide the method it will use.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R10	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R11	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R12	Moved to Requirement R7	This requirement has been moved to Requirement R7.
BAL-005-0.2b R13	Moved to Requirement R7	The portion of the requirement concerning common time synchronization was moved into Requirement R7. The portion of the requirement concerning an equipment error was moved into Requirement R7.
BAL-005-0.2b R14	Moved to Requirement R4 and Requirement R7	This requirement has been moved into Requirement R4 and Requirement R7.
BAL-005-0.2b R15	Retired	This requirement is duplicative of the intent of EOP-008 - Loss of Control Room Functionality. In addition, proposed R3 requires a performance level that the Balancing Authority Area must meet. The standard does not tell the BAA how to meet it.
BAL-005-0.2b R16	Moved to Requirement R4	This requirement has been moved into Requirement R4.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R17	Partially retired (partially captured in new Requirement R3)	This requirement which address accuracy of RTU and transducers is meaningless in today's world. RTUs do not quantize measurement anymore, these are done by relay or meters. Transducers are not used anymore and have been replaced by meters and relays which measure quantities. This requirement should be restored such that it actually supports an accurate calculation of ACE and proper operation of AGC by specifying accuracy requirements for all telemetry associated with ACE (Frequency, MW and the associated sensing devices and telemetry). In addition, the interpretation effective 8/27/2008 in BAL-005-0.2.b for R17 states that this requirement is specific to the equipment used to determine the frequency component required for reporting ACE. This is now being captured in Requirement R3.

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Project 2010-14.2.1 Mapping Document
Transition of BAL-005-0.2b to BAL-005-1

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-1 R1	~~This~~ Requirement R1 Part R1.1 and Part R1.2 have~~has~~ been moved into FAC-001-2 Requirement R3~~5~~ and~~,~~ R4~~6~~.~~ and R7~~ Requirement R1 Part R1.3 is being retired.	~~This r~~Requirements R1 Parts R1.1 and R1.2 do~~es~~ not provide for necessary information concerning the calculation of Reporting ACE. The requirement provides for information necessary when connecting to the electric system. Requirement R1 Part 1.3 is being retired in conjunction with the Risk-based Registration initiative de-certifying the LSE function.
BAL-005-0.2b R2	Retired	This requirement was retired as part of the original Paragraph 81 project. Its retirement was approved by FERC effective January 21, 2014.
BAL-005-0.2b R3	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7~~1 and Requirement R8~~.
BAL-005-0.2b R4	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7~~1 and Requirement R8~~.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R5	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7~~1 and Requirement R8~~.
BAL-005-0.2b R6	Moved to definition of Reporting ACE and Requirement R2~~3~~	The portion of the requirement concerning calculating ACE was moved into the definition for Reporting ACE. The portion of the requirement concerning an entity's inability to calculate Ace for more than 30 minutes was moved into Requirement R2~~3~~.
BAL-005-0.2b R7	Retire	This requirement should be retired under Paragraph 81 criteria. The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, though resources can be dispatched manually without any detriment to reliability. The SDT believes that the term "operate AGC" in R7 refers to the capability to continuously calculate ACE, not automatic control of resources to the extent BAs cannot take resources off "AGC" mode.
BAL-005-0.2b R8	The body of this requirement was moved to Requirement R1~~2~~ and Part 8.1 was moved into Requirement R3~~4~~	The body of this requirement has been moved to Requirement R1~~2~~ and Part 8.1 has been moved into Requirement R3~~4~~.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R9	Retire	R9 is covered in the definition of Reporting ACE, and the proposed R7~~1~~ ensures that the BA does not include any Interchange in its Reporting ACE that does not have an Adjacent BA. Regarding R9.1, the Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the Balancing Authority is not being instructed "how" to implement the HVDC link, but allowed to decide the method it will use.
BAL-005-0.2b R10	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R11	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R12	Moved to Requirement R7~~1~~	This requirement has been moved to Requirement R7~~1~~.
BAL-005-0.2b R13	Moved to ~~Requirement R1 and~~ Requirement R7	The portion of the requirement concerning common time synchronization was moved into Requirement R7~~1~~. The portion of the requirement concerning an equipment error was moved into Requirement R7.
BAL-005-0.2b R14	Moved to Requirement R4~~5~~ and Requirement R7~~8~~	This requirement has been moved into Requirement R4~~5~~ and Requirement R7~~8~~.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R15	Retired	This requirement is duplicative of the intent of EOP-008 - Loss of Control Room Functionality. In addition, proposed R3 requires a performance level that the Balancing Authority Area must meet. The standard does not tell the BAA how to meet it.
BAL-005-0.2b R16	Moved to Requirement R45	This requirement has been moved into Requirement R45.
BAL-005-0.2b R17	Partially retired (partially captured in new Requirement R34)	This requirement which address accuracy of RTU and transducers is meaningless in today's world. RTUs do not quantize measurement anymore, these are done by relay or meters. Transducers are not used anymore and have been replaced by meters and relays which measure quantities. This requirement should be restored such that it actually supports an accurate calculation of ACE and proper operation of AGC by specifying accuracy requirements for all telemetry associated with ACE (Frequency, MW and the associated sensing devices and telemetry). In addition, the interpretation effective 8/27/2008 in BAL-005-0.2.b for R17 states that this requirement is specific to the equipment used to determine the frequency component required for reporting ACE. This is now being captured in Requirement R34.

Project 2010-14.2.1 Mapping Document
Transition of BAL-006-2

Standard: BAL-006-2 – Inadvertent Interchange		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-006-2 R1	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.
BAL-006-2 R2	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.
BAL-006-2 R3	Moved to BAL-005-1 Requirement R7	This requirement directly impacts the ability to calculate an accurate Reporting ACE value.
BAL-006-2 R4	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.
BAL-006-2 R5	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.

Standard: BAL-006-2 – Inadvertent Interchange		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**

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Project 2010-14.2.1 Mapping Document

Transition of BAL-006-2 ~~to BAL-006-3~~

Standard: BAL-006-2~~3~~ – Inadvertent Interchange		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-006-2 R1	Retired~~No change~~	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.~~No change~~
BAL-006-2 R2	Retired~~No change~~	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.~~No change~~
BAL-006-2 R3	Moved to BAL-005-1 Requirement R7~~1 and Requirement R8~~	This requirement directly impacts the ability to calculate an accurate Reporting ACE value.
BAL-006-2 R4	Retired~~No change~~	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.~~No change~~

Standard: BAL-006-23 – Inadvertent Interchange		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-006-2 R5	Retired~~No change~~	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.~~No change~~

Standard Development Timeline

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

Description of Current Draft

This is the second posting of the draft standard for a 45-day formal comment period with an additional ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR posted for comment	July 16, 2014
Standard posted for 45-day comment and initial ballot	July 30, 2015

Anticipated Actions	Date
45-day formal comment period with additional ballot	November 2015 – January 2016
Final ballot	January 2016
NERC Board adoption	February 2016

New or Modified Terms 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.

Term: None

A. Introduction

1. **Title:** **Facility Interconnection Requirements**

2. **Number:** FAC-001-3

3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Applicable Generator Owner

   4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

5. **Effective Date:** See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

Rationale for Requirement R3.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the transmission will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 3.3, the Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

3.1. Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).

3.2. Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.

3.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

Rationale for Requirement R4.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the generation will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 4.3, the Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R4. Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

4.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified generation Facilities are within a Balancing Authority Area's metered boundaries.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

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 applicable Functional 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:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but	The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.	The Transmission Owner did not document Facility interconnection requirements.

				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
R2	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

R3	Long-term Planning	Lower	N/A	The Transmission Owner failed to address one part of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address two parts of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address Requirement R3 Part 3.1 through Part 3.3.
R4	Long-term Planning	Lower	N/A	The Generator Owner failed to address one part of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address two parts of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address Requirement R4 Part 4.1 through Part 4.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was "materially modified." Recognizing that what constitutes a "material modification" will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

Standard Development Timeline

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

Description of Current Draft

This is the second posting of the draft standard for a 45-day formal comment period with an additional ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR posted for comment	July 16, 2014
Standard posted for 45-day comment and initial ballot	July 30, 2015

Anticipated Actions	Date
45-day formal comment period with additional ballot	November 2015 – January 2016
Final ballot	January 2016
NERC Board adoption	February 2016

New or Modified Terms 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.

Term: None

A. Introduction

1. **Title:** **Facility Interconnection Requirements**

2. **Number:** FAC-001-3

3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Applicable Generator Owner

   4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

   ~~**4.1.3** Load Serving Entities~~

5. **Effective Date:** See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

Rationale for Requirement R3.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the transmission will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 3.3, the Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

3.1. Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).

3.2. Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.

3.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

Rationale for Requirement R4.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the generation will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 4.3, the Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R4. Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

4.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified generation Facilities are within a Balancing Authority Area's metered boundaries.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

~~**R5.** Each Transmission Owner with Transmission Facilities operating in an Interconnection shall confirm that each Transmission Facility is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*~~

~~**M5.** Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R5.~~

~~**R6.** Each Generator Owner with generation Facilities operating in an Interconnection shall confirm that each generation Facility is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*~~

~~**M6.** Each Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R6.~~

~~**R7.** Each Load-Serving Entity with Load operating in an Interconnection shall confirm that each Load is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*~~

~~**M7.** Each applicable Load Serving Entity shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R7.~~

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 applicable Functional Entity~~Transmission Owner and applicable Generator Owner~~ shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but	The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.	The Transmission Owner did not document Facility interconnection requirements.

				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
R2	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

R3	Long-term Planning	Lower	N/A	The Transmission Owner failed to address one part of Requirement R3 Part 3.1 through Part 3.3. ~~N/A~~	The Transmission Owner failed to address two parts of Requirement R3 Part 3.1 through Part 3.3. ~~The Transmission Owner addressed either R3, Part 3.1 or Part 3.2 in its Facility interconnection requirements, but did not address both.~~	The Transmission Owner failed to address Requirement R3 Part 3.1 through Part 3.3. ~~The Transmission Owner addressed neither R3, Part 3.1 nor Part 3.2 in its Facility interconnection requirements.~~
R4	Long-term Planning	Lower	N/A	The Generator Owner failed to address one part of Requirement R4 Part 4.1 through Part 4.3. ~~N/A~~	The Generator Owner failed to address two parts of Requirement R4 Part 4.1 through Part 4.3. ~~The applicable Generator Owner addressed either R4, Part 4.1 or Part 4.2 in its Facility interconnection requirements, but did not address both.~~	The Generator Owner failed to address Requirement R4 Part 4.1 through Part 4.3. ~~The applicable Generator Owner addressed neither R4, Part 4.1 nor Part 4.2 in its Facility interconnection requirements.~~

R5	Long-term Planning	Medium	N/A	N/A	N/A	The Transmission Operator with Transmission Facilities operating in an Interconnection failed to ensure that those Transmission Facilities were included within metered boundaries of a Balancing Authority Area.
R6	Long-term Planning	Medium	N/A	N/A	N/A	The Generation Operator with generation Facilities operating in an Interconnection failed to ensure that those generation Facilities were included within metered boundaries of a Balancing Authority Area.
R7	Long-term Planning	Medium	N/A	N/A	N/A	The Load-Serving Entity with Load operating in an Interconnection failed to ensure that those Loads were included within metered boundaries of a Balancing Authority Area.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was "materially modified." Recognizing that what constitutes a "material modification" will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

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Project 2010-14.2.1 Mapping Document
Transition of FAC-001-2 to FAC-001-3

Standard: FAC-001-3 – Facility Interconnection Requirements		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
FAC-001-2 R1	No change	No change
FAC-001-2 R2	No change	No change
FAC-001-2 R3	No change	No change
FAC-001-2 R4	No change	No change
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R3 Part 3.3	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R4 Part 4.3	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.

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Standard: FAC-001-3 – Facility Interconnection Requirements		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
FAC-001-2 R1	No change	No change
FAC-001-2 R2	No change	No change
FAC-001-2 R3	No change	No change
FAC-001-2 R4	No change	No change
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R3~~5~~ Part 3.3	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R4~~6~~ Part 4.3	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.
~~BAL-005-0.2b R1~~	~~Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R7~~	~~This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.~~

Calculating and Using Reporting ACE in a Tie Line Bias Control Program

Introduction:

Tie Line Bias[1] (TLB) control has been used as the preferred control method in North America for 75 years. In the early 1950's the term Area Control Error (ACE) was developed for the specific implementation of coordinated Tie Line Bias control now in use throughout the world. This document provides responsible entities guidelines for using both required specifics and the best practices for calculating and using Reporting ACE[2] in coordination with other measures to provide reliable frequency control. While the incorporation of these best practices is strictly voluntary; reviewing, revising, or developing a process using these practices is highly encouraged to promote and achieve reliability for the Bulk Electric System.

The following definitions are included in the NERC Glossary:

Definition:

Actual Frequency **F_A** **5/11/2015**

The Interconnection frequency measured in Hertz (Hz).

Definition:

Actual Net Interchange **NI_A** **5/11/2015**

The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, with all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Actual Net Interchange.

[1] Capitalized terms hold the same definition as in the NERC glossary throughout this document.

[2] The CPS1 measure was among the first of the results based measures developed by NERC. It defined not how to perform control, but instead defined the target control results that were to be achieved, and a method to measure whether or not that defined control target had been met. As a result, when CPS1 was implemented, the ACE Equation used in that measure was also specified within that standard.

Historically, Area Control Error (ACE) has been used to describe many terms involved in TLB Control. Within a BAA's Automatic Generation Control (AGC) algorithm there may be more than one ACE value in use. In some systems, the ACE is filtered prior to determining control actions in order to smooth the control signals; or, there may be additional "feed-forward" terms added to ACE in anticipation of future changes (e.g. anticipated ramps, changes in ambient light at sunrise or sunset). There may be gain terms that modify certain variables such as the Frequency Bias Setting to improve the quality of control for the specific characteristics of that particular BAA.

Some auditors have raised compliance issue related to the use of such modifications to the ACE used within the Load-Frequency Control (LFC) system (also referred to as AGC) and required changes in the AGC system to conform to the definition of ACE in BAL-001. The term "Reporting ACE" was developed and is used in place of the term ACE to provide a consistent performance measurement using Reporting ACE and to remove any unnecessary restrictions on the specification of ACE within the LFC system.

Definition:

Automatic Time Error Correction **I_{ATEC}** **5/11/2015**

The addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back primary Inadvertent Interchange (PII) to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$$I_{\mathbf{ATEC}} = \frac{\boldsymbol{PII}_{accum}^{on/off\ peak}}{(\mathbf{1-Y})*\mathbf{H}}$$ when operating in Automatic Time Error Correction mode.

The absolute value of I_{ATEC} shall not exceed L_{max} .

I_{ATEC} shall be zero when operating in any other AGC mode.

- L_{max} is the maximum value allowed for I_{ATEC} set by each BAA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- **Y** = B_i / B_S.
- **H** = Number of hours used to payback primary Inadvertent Interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1\text{-}Y) * (II_{actual} - B_i * \Delta TE/6)$
- II_{actual} is the hourly Inadvertent Interchange for the last hour.
- **ΔTE** is the hourly change in system Time Error as distributed by the Interconnection time monitor,

  where: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection time monitor control center clocks.
- **t** is the number of minutes of manual Time Error Correction that occurred during the hour.
- TE_{offset} is 0.000 or +0.020 or -0.020.
- PII_{accum} is the Balancing Authority Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,

  where:

$$\boldsymbol{PII}_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ \boldsymbol{PII}_{accum}^{on/offpeak} + \boldsymbol{PII}_{hourly}$$

Definition:

Frequency Bias Setting **B** **4/1/2015**

A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority Area's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.

Definition:

Interchange Meter Error **I_{ME}** **5/11/2015**

A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Definition:

Reporting ACE **RACE** **5/11/2015**

The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

Reporting ACE is calculated as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Reporting ACE is calculated in the Western Interconnection as follows:

$$\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

Where**:**

- NI_A = Actual Net Interchange.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections with multiple Balancing Authority Areas operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Definition:

Scheduled Frequency **F_S** **3/16/2007**

60.0 Hz, except during a manual Time Error Correction.

Definition:

Scheduled Net Interchange **NI_S** **5/11/2015**

The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Structure:

The effective use of Reporting ACE within a TLB control program should address the following components:

(I) Management Roles and Expectations
(II) Information Technology Roles
(III) System Operator Roles
(IV) Manual Source Data Entry
(V) Automatically Collected Source Data
(VI) Uses of Reporting ACE
(VII) Historic Data Management
(VIII) Special Conditions and Calculations

Each individual component should address processes and procedures, evaluation of any issues or problems along with solutions, testing, training, and communications. These provisions and activities together will be referred to as the Tie Line Bias control program.

Each responsible entity should evaluate all of its uses for Reporting ACE in its operations and its reliability measurement. Reporting ACE is one of the most important single measurements available to indicate the current state of the Responsible Entity's contribution to interconnection reliability.[3] Reporting ACE is also used as an integral part of the measurements used in BAL-001 and BAL-002. Technical requirements associated with the parameters used in the calculation of Reporting ACE are specified in BAL-003 and BAL-005.

I. Management Roles and Expectations

Management plays an important role in maintaining an effective TLB control program. The management role and expectations below provide a high-level overview of the core management responsibilities related to each Tie Line Bias control program. The management of each responsible entity should tailor these roles and expectations to fit within its own structure.

a. Set expectations for safety, reliability, and operational performance.

[3] When configured with a Frequency Bias Setting equal to the actual Frequency Response of the BAA, Reporting ACE will reflect the BAA's obligation to match its actual interchange, less the impact from its current Frequency Response offset, to its scheduled interchange.

b. Assure that a TLB control program exists for each responsible entity and is current.
c. Provide annual training on the TLB control program and its purpose and requirements.
d. Ensure the proper expectation of TLB control program performance.
e. Share insights across industry associations.

II. Information Technology (IT) Roles

a. Participate in appropriate TLB control related training.
b. Ensure the Reporting ACE and source information are always current and correct.
c. Implement the TLB control program in Real-time.
d. Ensure that the EMS supports the manual data entry of all source data required to be entered by IT staff, system operations staff, and System Operators and properly manages that data once entered.
e. Ensure that the EMS supports and manages the automatic collection of all source data that is required to be measured in real-time through telemetry and data exchange including data quality information to indicate data validity.
f. Ensure that the programs that manage data used to calculate components of Reporting ACE, Reporting ACE itself, and subsequent measures based on Reporting ACE are up to date and correct as identified by, but not limited to the following calculations and equations:

    1) Actual Net Interchange[4] (NI_A):

        All BAAs involved account for the power exchange and associated transmission losses as actual interchange between the BAAs, both in their ACE and Reporting ACE equations and throughout all of their energy accounting processes.

        i. Calculate for each scan.[5]
        ii. Integrated hourly average calculated for each hour as an integration of the scan rate values.

[4] By definition "Actual megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Actual Net Interchange." Additional information on asynchronously connected DC tie lines connected to another interconnection is provided in "Special Conditions and Calculations" section of this document.

[5] Actual Net Interchange scan-rate values are also used as one of the primary inputs to the calculation of Frequency Response Measure (FRM) on FRS Form 1 and FRS Form 2.

2) Scheduled Net Interchange[6] (NI_S):
   i. Calculate for each scan.
   ii. Integrated hourly average calculated for each hour as an integration of the scan rate values. (This value differs from the block accounting value.)

   Note: Dynamic Schedules are to be accounted for as Interchange Schedules by the source, sink, and contract intermediary BAA(s), both in their respective ACE and Reporting ACE equations, and throughout all of their energy accounting processes.

3) Frequency Error ($\Delta F = (F_A - F_S)$):
   i. Calculate for each scan.
   ii. Calculate clock-minute average from valid samples available within each clock-minute[7] where at least half of the scan-rate samples are valid.

4) Frequency Trigger Limit – Low (FTL_{Low})[8]:

   Calculate the Frequency Trigger Limit – Low for each clock-minute where at least half of the scan rate samples are valid by subtracting three times Epsilon1 from the Scheduled Frequency (F_S).

5) Frequency Trigger Limit – High (FTL_{High})[9]:

   Calculate the Frequency Trigger Limit – High for each clock-minute where at least half of the scan rate samples are valid by adding three times Epsilon1 to the Scheduled Frequency (F_S).

6) Accumulated primary Inadvertent Interchange (PII): Calculated each hour for WECC BAAs only.

$$\boldsymbol{PII}_{\boldsymbol{accum}}^{\boldsymbol{on/offpeak}} = \boldsymbol{last\ period's}\ \boldsymbol{PII}_{\boldsymbol{accum}}^{\boldsymbol{on/offpeak}} + \boldsymbol{PII}_{\boldsymbol{hourly}}$$

7) Automatic Time Error Correction (IATEC): Calculate for each hour for WECC BAAs only for inclusion in the ACE and Reporting ACE Equation for the next hour.

$\boldsymbol{I}_{\mathbf{ATEC}} = \dfrac{\boldsymbol{PII}_{\boldsymbol{accum}}^{\boldsymbol{on/off\ peak}}}{(\mathbf{1}-\boldsymbol{Y})*\boldsymbol{H}}$ when operating in ATEC mode.

The absolute value of $\mathbf{I_{ATEC}}$ shall not exceed $\mathbf{L_{max}}$.

$\mathbf{I_{ATEC}}$ shall be zero when operating in any other AGC mode.

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[6] By definition "Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another interconnection are excluded from Scheduled Net Interchange." Additional information on asynchronously connected DC tie lines connected to another interconnection is provided in the "Special Conditions and Calculations" section of this document.

[7] Clock-minute averages are used for the calculation of ACE and Frequency Error in CPS1 and BAAL to eliminate the transient variations of tie-line flows and frequency error used in the calculation of performance measures. The one-minute period was chosen because it is evenly divisible by all whole-second scan rates less than the maximum specified scan rate of six seconds. This assures greater comparability of performance data among BAs with different scan rates.

[8] This variable could be entered manually as long as it is changed every time a manual time error correction is started or stopped. If manual time error correction is eliminated, it could become a constant and entered manually.

8) Reporting ACE:
   i. Calculate for each scan.
   ii. Calculated average for each clock-minute for BAAs using a fixed Frequency Bias Setting when at least half of the values are valid.[9]

9) Compliance Factor[10]:
   i. Calculate for each scan where both Reporting ACE and Frequency Error are valid.
   ii. Calculate for each clock-minute where both the average clock-minute Frequency Error and the average clock-minute Reporting ACE are valid.[11]

10) Clock-hour compliance factor[8]:

    Calculate for each hour by summing the valid clock-minute compliance factors for the hour and dividing by the number of valid clock-minute compliance factors in the hour.

11) Month compliance factor[8]:

    Calculate by summing the valid clock-minute compliance factors in the month and dividing by the number of valid clock-minute compliance factors in the month.

12) 12-month compliance factor[8]:

    Calculate by summing the valid clock-minute compliance factors in the 12-month period and dividing by the number of valid clock-minute compliance factors in the 12-month period.

13) CPS1 compliance factor:

    Calculate the CPS1 compliance factor by dividing the 12-month compliance factor by the square of the $Epsilon_1$ value for the Interconnection.

14) CPS1:
   i. Calculate the CPS1 scan rate performance by dividing the scan rate compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each scan with a valid compliance factor.
   ii. Calculate the CPS1 clock-minute performance by dividing the clock-minute compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.
   iii. Calculate the CPS1 clock-hour performance by dividing the clock-hour compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2

[9] The average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the Frequency Bias Setting for those BAs using a variable Frequency Bias Setting, where at least half of the ratio values are valid.

[10] Used for CPS1.

[11] The compliance factor is calculated when the average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the Frequency Bias Setting for those BAs using a variable Frequency Bias Setting, where at least half of the ratio values are valid and the average clock-minute Frequency Error is valid.

and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

iv. Calculate the CPS1 monthly performance by dividing the month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

v. Calculate the CPS1 12-month performance by dividing the 12-month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

15) Balancing Authority ACE Limit - Low ($BAAL_{Low}$):

i. Calculate the scan rate Balancing Authority ACE Limit – Low by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the Frequency Error.

ii. Calculate the clock-minute Balancing Authority ACE Limit – Low by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the clock-minute Frequency Error when at least half of the values are valid.

16) Balancing Authority ACE Limit - High ($BAAL_{High}$):

i. Calculate the scan rate Balancing Authority ACE Limit – High by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the Frequency Error.

ii. Calculate the clock-minute Balancing Authority ACE Limit – High by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the clock-minute Frequency Error when at least half of the values are valid.

17) Balancing Authority ACE Limit - Low Compliance:

i. Alarm $BAAL_{Low}$ potential non-compliance for each period as determined for operations where the clock-minute Reporting ACE is below the clock-minute $BAAL_{Low}$.

ii. Indicate $BAAL_{Low}$ non-compliance for each period where the clock-minute Reporting ACE is below the clock-minute $BAAL_{Low}$ for more than 30-consecutive clock-minutes.

18) Balancing Authority ACE Limit - High Compliance:

i. Alarm $BAAL_{High}$ potential non-compliance for each period as determined for operations where the clock-minute Reporting ACE is above the clock-minute $BAAL_{High}$.

ii. Indicate $BAAL_{High}$ non-compliance for each period where the clock-minute Reporting ACE is above the clock-minute $BAAL_{High}$ for more than 30 consecutive clock minutes.

g. Ensure that the EMS supports the retention of all historic data including data quality information required to be retained to support continuing operations and audit requirements.

h. Ensure that the EMS supports and manages the presentation of all information required to be available to the System Operator for real-time operations, operations staff for evaluation of operations, and auditors for compliance confirmation.

i. Conduct an evaluation of the effectiveness of the TLB control program and incorporate lessons learned.

III. System Operator and Operations Staff Roles

a. Participate in appropriate TLB control related training.
b. Ensure the Reporting ACE information is always current and correct.
c. Conduct an evaluation of the effectiveness of the TLB control program and incorporate lessons learned.
d. Implement the TLB control program in Real-time.

IV. Manual Source Data Entry

Reporting ACE is calculated in Real-time, at least every six seconds[12], by the Responsible Entity's Energy Management System (EMS), and may be partially based on source data manually entered into that system. The following source data may be entered:

NI_A (Actual Net Interchange): The telemetry values of actual tie flows, including pseudo-ties, between Adjacent Balancing Authority Areas may not be available from an automatic collection source, requiring manual entry of estimated flows. These manual entries should be performed in a manner that reasonably assures equal magnitude and opposite sign values are used by the Adjacent Balancing Authority Areas entering the manual data. If the actual flow estimates are the same for the Adjacent Balancing Authority Areas, the effect of any errors will be confined to the two Adjacent Balancing Authority Areas responsible for the manual entries. Failure to match actual flow estimates will result in errors that affect other BAAs on the Interconnection.

NI_S (Scheduled Net Interchange): The power transfer schedules, including the schedule ramps where applicable, are processed by the EMS. If scheduled flow estimates are equal and have opposite signs for the Adjacent Balancing Authority Areas, the effect of any errors will be confined to the two Adjacent Balancing Authority Areas responsible for the manual entries. Failure to match scheduled flow estimates will result in errors that affect other BAAs on the Interconnection.

B (Frequency Bias Setting): The Frequency Bias Setting, or minimum required value, for the Balancing Authority Area is specified by calculations performed as part of compliance with BAL-003-1 - Frequency Response and Frequency Bias Setting;

R2. Each Balancing Authority Area that is a member of a multiple Balancing Authority Area Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error

[12] BAL-005-1 Balancing Authority Control - R2. The Balancing Authority shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE.

(ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO.[13]

10 is the factor (10 0.1Hz/Hz) that converts the Frequency Bias Setting units to MW/Hz.

F_S (Scheduled Frequency): Scheduled Frequency, normally 60 Hz, is manually adjusted on a coordinated basis when directed to do so by the Interconnection Time Monitor as specified in BAL-004-0.[14] It is important for all BAAs on an interconnection to make these adjustments on a coordinated basis so that all BAAs are controlling to the same Scheduled Frequency at all times.

I_{ME} (Interchange Meter Error): This term, normally zero, is available for use by the System Operator or operations staff to add a correction term in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components identified by analysis of historic data demonstrating the existence of errors, usually errors between integrated hourly scan-rate data and hourly agreed to accumulated meter data. (See the Special Conditions and Calculations section of this document for additional information)

L_{max} is the maximum value allowed for **I_{ATEC}** set by each BA between $0.2*|B|$ and L_{10}, $0.2*|B| \leq L_{max} \leq L_{10}$.

Y is normally calculated by the ATEC program in the EMS for BAAs on the Western Interconnection.

H is normally set to 3 and used by the ATEC program in the EMS for BAs on the Western Interconnection. It represents the number of hours over which the primary inadvertent interchange is paid back.

B_S is used by the ATEC program in the EMS for BAAs on the Western Interconnection. It represents the sum of the minimum Frequency Bias Settings for all BAAs on the Interconnection.

ΔTE is used by the ATEC program in the EMS for BAAs on the Western Interconnection. In some cases, it may be calculated by the EMS based on the factors in the ΔTE equation. ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor.

TD_{adj} is an adjustment for the differences between the local clock in the local time standard and the Interconnection time monitor control center clocks so that the local EMS can calculate the correct ΔTE for the BAAs and used by the ATEC program in the EMS for BAAs on the Western Interconnection.

TE_{offset} is entered as instructed by the Interconnection time monitor.

ε_1 is the RMS Limit for the 1-minute average frequency error for the interconnection.

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[13] As a note of interest, the new procedures put forth with BAL-003-1 will result in the reduction of minimum Frequency Bias Setting values on the multiple BA interconnections to bring them closer to the natural measured Frequency Response of the interconnection. The rule requiring a minimum Frequency Bias Setting of 1% of peak load in the NERC Standards dates back to 1962 when NAPSIC, the precursor to the NERC Operating Committee, codified the recommendations of the Interconnected Systems Group made in 1956 to set a minimum of 50% of the natural measured response which was 2% of peak load at that time. The 1% figure is now more than 200% of the natural measured response for the Eastern Interconnection and in some cases is approaching a value that could result in instability by being too high. The logic justifying a minimum of the natural response is still valid.

[14] This is consistent with condition 3 in the Reporting ACE Definition: "The use of a common Scheduled Frequency F_S for all areas at all times."

V. Automatically Collected Source Data

Reporting ACE is calculated in Real-time, at least as frequently as every six seconds[15], by the responsible entity's Energy Management System (EMS) predominantly based on source data automatically collected by that system. Also, the data must be updated at least every six seconds for continuous scan telemetry and updated as needed for report-by-exception telemetry.

In addition, data quality information (usually in the form of data quality flags associated with each data value) must be retained and presented in real-time to the System Operators. This data quality information is presented to the System Operator to have situational awareness with respect to the quality of the data inputs and final calculated result. It is later used to determine which data is valid for use in performance calculations such as CPS1, BAAL, DCS, and frequency response obligation (FRM).

NI_A (Actual Net Interchange): The tie-line value representing each tie-line flow and pseudo-tie quantity is collected at the required scan rate of six seconds or less.[16,17,18,19] Data that is of questionable accuracy or timeliness is flagged with an appropriate data quality flag. This information is presented to the System Operator to support situational awareness.[20] The EMS sums the individual flow values on all tie lines and pseudo ties with all adjacent BAAs at the scan rate and includes this value as NI_A in the Reporting ACE equation calculation. The result is a series of NI_A values at the EMS scan rate and associated data quality flags. The associated data quality of the telemetry element is passed to the result of all calculations using that element.

NI_S (Scheduled Net Interchange): Most interchange schedules and some Dynamic Schedules are entered into the EMS in a summary format either as individual schedules, schedule nets with each Adjacent Balancing Authority Area, or a final Scheduled Net Interchange. These schedules are converted into scan-rate schedules by the EMS. The EMS calculates the Scheduled Net Interchange, where applicable, by summing all individual schedule values or nets with each Adjacent Balancing Authority Area for all regular and Dynamic Schedules and includes the result as NI_S in the ACE equation.

F_A (Actual Frequency): Actual frequency is provided by a frequency measuring device at the accuracy specified in BAL-005[21] at the EMS scan rate. If a frequency value is not available, the value for that scan is marked invalid.

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[15] BAL-005-1 Balancing Authority Control – "R2. The Balancing Authority Area shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE."

[16] Data transmitted at a rate slower than the scan rate of the remote sensing equipment may require the inclusion of anti-aliasing filtering at the source of the measurement to eliminate the risk of aliasing in the data transmitted to the EMS. See the attached document titled "Anti-aliasing Filtering."

[17] It is acceptable to collect tie-line flow data from RTUs that use report by exception as long as those RTUs can support the scan rate of six seconds or less when data is changing rapidly and both adjacent BAAs are receiving comparable data to keep the measured flows equivalent.

[18] The six-second scan rate not only assures that data collected is close to Real-time, it also limits the latency (time skew) associated with the data collection.

[19] The accuracy of the flow data is set by those using the flow data for transmission flow management. As with all ACE data, as long as both adjoining BAAs are using the same values for tie-line flow, the effects of any error in flow measurement will be confined to the two adjacent BAAs.

[20] Indications of suspect data are usually indicated with color changes and/or alarms.

[21] BAL-005 – Automatic Generation Control specifies an accuracy of ≤0.001 Hz (equivalent to ≤ +/- 0.0005 Hz) for the Digital Frequency Transducer.

II_{actual} (Inadvertent Interchange): This term is only used in the Western Interconnection ACE calculation. Inadvertent Interchange "Actual" for the previous hour is calculated by the EMS from the previous hour's data as the difference between the integrated hourly average Scheduled Net Interchange and the integrated hourly average Actual Net Interchange. (Block schedules are not used for this calculation.)

t (Manual Time Error correction minutes in the hour): The number of minutes of manual Time Error correction in the hour.

VI. Uses of Reporting ACE

a. Reporting ACE is currently used to measure secondary frequency control within TLB control on all of the Interconnections.[22] Consequently, Reporting ACE is one of the primary measurement parameters in many of the NERC Balancing Standards. The following standards require the use of Reporting ACE as part of the performance metrics or set requirements associated with the calculation of Reporting ACE.

   i. BAL-001-1 – Real Power Balancing Control Performance and BAL-001-2 – Real Power Balancing Control Performance.

   ii. BAL-002-1 – Disturbance Control Performance and BAL-002-2 – Disturbance Control Standard – Contingency Reserve from a Balancing Contingency Event (when approved).

   iii. BAL-005-0.2b – Automatic Generation Control and BAL-005-1 – Balancing Authority Control (when approved).

   iv. BAL-006-2 Inadvertent Interchange.

b. The industry may also consider the use of Reporting ACE in the future to evaluate the rules associated with transmission loading.

VII. Historic Data Management

The industry currently requires the retention of data supporting the calculation of Reporting ACE and compliance measurements based in part on Reporting ACE to support the NERC compliance audit process. This data retention must be considered as an integral part of the Reporting ACE and "TLB control program".

VIII. Special Conditions and Calculations

IX. **I_{ME} (Interchange Meter Error):** BAL-005-1 R6 requires, "Each Balancing Authority Area that is within a multiple Balancing Authority Area interconnection shall implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE." Ideally, errors identified should be corrected immediately, but this is not always possible. The **I_{ME}** term, normally zero, can be used by the System Operator or operations staff to add a correction term in the Reporting ACE calculation correcting errors affecting the scan-rate accuracy of data, thus mitigating the error in the calculation of Reporting ACE until telemetry errors can be corrected.

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[22] On single BAA Interconnections, the ACE Equation reduces to a single term, **$-10B (F_A – F_S)$**, because there are no tie lines or schedules to include in the first term, **$(NI_A – NI_S)$**, and there is no **I_{ME}** term to correct for tie line or dynamic schedule measurement errors in the first term.

The calculation of the $\mathbf{I_{ME}}$ is the one of the results of this required Operating Process. It compensates for data or equipment errors affecting components of Reporting ACE identified by analysis of historic data. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs. The process used for including adjustments in the $\mathbf{I_{ME}}$ term should be based on good quality control methods.[23]

The goal associated with the use of the $\mathbf{I_{ME}}$ is to encourage the scan-rate values of actual and scheduled interchange between Adjacent Balancing Authorities to be equal in magnitude and have opposite signs.[24] Unfortunately, these values cannot be directly compared with each other because of differences between scan time and differences between scan-rates between BAAs. When initially configured, all BAs used "Digital to Analog" converters and "Analog to Digital" converters to transmit tie-line flows and accumulated MWh values from the common metering point required in the standards to the BA's EMS. These "D to A" and "A to D" converters are subject to error and require frequent calibration, and although, many have been replaced by digital telemetry, they still exist and require oversight. Any difference between the scan-rate values agreed to by Adjacent BAAs that is not included in the error mitigation process will be passed to the interconnection for management and will not be included in the performance measures such as CPS1, BAAL and FRM.

Energy Management Systems are capable of integrating the scan-rate values used for the calculation of Reporting ACE and providing those integrated values for comparison to the accumulated megawatt-hour values for the same meters. If the integrated scan rate values are close to the accumulated megawatt-hour values, then one can conclude that the scan-rate values accurately represent the accumulated values. The final step in this process includes a comparison and agreement on the accumulated megawatt-hour values between the Adjacent BAAs sharing the measurement. If the differences between accumulated values between Adjacent BAAs is not included in this process, any adjustments to the accumulated values made by a BAA to achieve agreement with an adjacent BAA will be excluded from the analysis and will not be mitigated. This information used in conjunction with a similar analysis of the scan rate values for the same measurement by the Adjacent Balancing Authority Area including analysis of any differences between the accumulated values and the agreed to accumulated values. This total process provides reasonable assurance that the scan-rate tie line flows or the dynamic schedules used by Adjacent BAAs are consistent with one another confining control problems within the boundaries of the Adjacent BAAs.

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[23] Adjustments to the $\mathbf{I_{ME}}$ term should follow good quality control methods and exclude tampering as demonstrated by the Deming's Funnel Experiment, http://blog.newsystemsthinking.com/w-edwards-deming-and-the-funnel-experiment/ .

[24] As long as the scan-rate tie line flows and scheduled flows match for Adjacent Balancing Authority Areas, any problems with the measurement of balancing on the interconnection will be confined to within the boundaries of those Adjacent Balancing Authority Areas. Any mismatch will pass the difference to the interconnection and will result in frequency control error that will to be excluded from performance measurement and managed by all BAAs through the frequency bias terms of their Reporting ACE.

These error correction adjustments can be used to correct errors in the $\mathbf{NI_A}$ or $\mathbf{NI_S}$[25] terms for Reporting ACE and other measurements that depend upon an accurate Actual Net Interchange and/or an accurate Scheduled Net Interchange. The same logic and evaluation processes that are valid for inclusion in the $\mathbf{I_{ME}}$ term of the Reporting ACE equation should also be valid as adjustments to the scan rate tie-line flows used for the measurement of Frequency Response as part of the BAL-003-1.

a. Use of Source-Sink Pairs for Asynchronous DC Tie Lines to Another Interconnection: One of the primary rules for insuring the validity of the Reporting ACE equation is, "All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss." This is accomplished by requiring the inclusion in Reporting ACE of all tie lines, pseudo ties, interchange schedules and Dynamic Schedules to Adjacent Balancing Authority Areas and only Adjacent Balancing Authority Areas on the same Interconnection, and requiring the exclusion of all asynchronous DC tie lines and associated scheduled interchange with Balancing Authority Areas on a different Interconnection from Reporting ACE. Following this simple rule insures that all loads, losses and generation are properly included with each Interconnection.

Instead of including the power transfers from an asynchronous DC tie line between two Interconnections as a normal interchange transfer between two BAAs, this form of power transfer should be included as though it is a linked source-sink pair for the purposes of managing frequency control within a tie line bias control program. One terminal of an asynchronous DC tie line will appear to the receiving Interconnection and receiving BAA as an energy resource similar to a generator. This is the source end of the source-sink pair. The other terminal of the same asynchronous DC tie line will appear to the supplying Interconnection and supplying BAA as an energy sink similar to a load. This is the sink end of the source-sink pair.

Interchange transactions linked to either the source or sink from other BAAs on the same Interconnection as the source or sink will schedule those transactions, include those transactions in Reporting ACE, and manage those transactions in a similar manner to any other energy transaction. Only the BAA acting as the source or the sink for the DC tie line will exclude the asynchronous tie line from its Reporting ACE while including all transactions with Adjacent BAAs on the same Interconnection associated with that source or sink power transfer in their Reporting ACE.

[25] Errors in the $\mathbf{NI_S}$ would only occur and only support correction in cases where there is a measurement error associated with a Dynamic Schedule.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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?):
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 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.

SAR Information

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 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
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to 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."
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 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."
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," 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 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." 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 report.

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.
☐ 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.

Reliability Functions		
☐	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

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
1	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 82.61% Approval: 80.73%			
2	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 83.01% Approval: 79.89%			
3	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 88.83% Approval: 95.43%			
4	Project 2008-07	Interpretation Request - EOP-002 - Brookfield_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 89.67% Approval: 76.47%			
5	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_rc	Recirculation Ballot	6/13/2008	6/22/2008	Quorum: 89.36% Approval: 95.21%			
6	Project 2008-09	Request for Interpretation - EOP-001-0 - RECM_in	Initial Ballot	6/19/2008	7/2/2008	Quorum: 84.82% Approval: 85.79%			
7	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.57% Approval: 79.13%			
8	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.98% Approval: 78.31%			
9	Pre-2006	IROL Standard - IRO-010_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.71% Approval: 88.40%			
10	Pre-2006	IROL Standard - IRO-009_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.63% Approval: 89.44%			
11	Pre-2006	IROL Standard - IRO-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.67% Approval: 91.71%			
12	Project 2006-07	ATC et al Standard - MOD-030_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.37% Approval: 56.56%			
13	Project 2006-07	ATC et al Standard - MOD-029_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.67% Approval: 92.62%			
14	Project 2006-07	ATC et al Standard - MOD-028_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.64% Approval: 79.47%			
15	Project 2006-07	ATC et al Standard - MOD-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.27% Approval: 80.44%			
16	Project 2006-07	ATC et al Standard - MOD-001_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.02% Approval: 75.97%			
17	Project 2008-10	Request for Interpretation - CIP-006-1 - Progress Energy_in	Initial Ballot	8/7/2008	8/16/2008	Quorum: 88.18% Approval: 21.52%			
18	Pre-2006	IROL Standard - IRO-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.72% Approval: 89.49%			
19	Pre-2006	IROL Standard - IRO-009_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.68% Approval: 86.53%			
20	Pre-2006	IROL Standard - IRO-010_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 85.95%			
21	Project 2006-07	ATC et al Standards - MOD-001_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 94.87% Approval: 76.83%			
22	Project 2006-07	ATC et al Standard - MOD-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.15% Approval: 81.49%			
23	Project 2006-07	ATC et al Standard - MOD-028_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.54% Approval: 79.34%			
24	Project 2006-07	ATC et al Standard - MOD-029_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.56% Approval: 92.24%			
25	Project 2006-07	ATC et al Standard - MOD-030_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.24% Approval: 74.26%			
26	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_in	Initial Ballot	9/9/2008	9/17/2008	Quorum: 85.78% Approval: 90.37%			
27	Project 2006-07	ATC et al Standard - MOD-004_in	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.26% Approval: 66.29%			
28	Project 2007-14	Permanent Changes to CI Timing Tables_in	Initial Ballot	9/12/2008	9/22/2008	Quorum: 79.74% Approval: 100.00%			
29	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rb	Re-ballot	10/6/2008	10/24/2008	Quorum: 82.61% Approval: 74.67%			
30	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_in	Initial Ballot	10/21/2008	10/30/2008	Quorum: 83.33% Approval: 96.94%			
31	Project 2006-01	Project 2006-01 - PER-005-1_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 90.13% Approval: 82.47%			
32	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 89.13% Approval: 70.01%			
33	Project 2006-07	ATC et al Standard - MOD-004_rc	Recirculation Ballot	10/28/2008	11/6/2008	Quorum: 91.49% Approval: 83.71%			
34	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_in	Initial Ballot	12/1/2008	12/10/2008	Quorum: 83.77% Approval: 86.51%			

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
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%			
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%			

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
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%			
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%			

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
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%			
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%			

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
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		
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		

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
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%			
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%			

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
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%			
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%			

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
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%			
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		

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
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		
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%			

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
307	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot	9/11/2012	9/20/2012	Quorum: 77.70% Approval: 50.57%	Support 9/15/12		
308	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	9/11/2012	9/20/2012	Quorum: 84.05% Approval: 54.07%			
309	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	9/12/2012	9/21/2012	Quorum: 85.36% Approval: 87.34%			
310	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	9/18/2012	9/27/2012	Quorum: 78.54% Approval: 63.40%	No Consensus 9/27/12		
311	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	9/18/2012	9/27/2012	Quorum: 78.93% Approval: 71.04%			
312	Project 2009-19	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	9/28/2012	10/8/2012	Quorum: 85.11% Approval: 90.34%	Support 2/22/10		
313	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 74.85%	Support 10/4/12		
314	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.37% Approval: 89.50%	Support 10/4/12		
315	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 85.58%	Support 10/4/12		
316	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 89.46%	Support 10/4/12		
317	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.11%	Support 10/4/12		
318	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 87.73%	Support 10/4/12		
319	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.74%	Support 10/4/12		
320	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.73%	Support 10/4/12		
321	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 84.60%	Support 10/4/12		
322	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.90%	Support 10/4/12		
323	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	10/1/2012	10/10/2012	Quorum: 78.93% Approval: 94.00%	Support 10/4/12		
324	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	10/1/2012	10/10/2012	Quorum: 79.13% Approval: 91.59%	Support 10/4/12		
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			
331	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.34% Approval: 71.53%			
332	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.07% Approval: 70.64%			
333	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.88% Approval: 77.10%			
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		

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
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 93.73%	Support 10/4/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.53%	Support 10/4/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 91.79%	Support 10/4/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.47%	Support 10/4/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 94.60%	Support 10/4/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 88.99%	Support 10/4/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.67%	Support 10/4/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation Plan	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 94.91%	Support 10/4/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 93.23%	Support 10/4/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Recirculation Ballot	10/24/2012	11/5/2012	Quorum: 85.14% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		
353	Project 2010-11	Project 2010-11 TPL footnote b Initial Ballot October 2012 in	Initial Ballot	11/9/2012	11/19/2012	Quorum: 80.45% Approval: 56.18%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/5/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/5/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 75.77% Approval: 96.45%	Support 12/10/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	12/4/2012	12/13/2012	Quorum: 76.78% Approval: 53.57%	No Consensus 12/13/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	12/4/2012	12/13/2012	Quorum: 77.22% Approval: 57.91%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Successive Ballot	12/7/2012	12/17/2012	Quorum: 76.47% Approval: 33.23%	Oppose 12/17/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	12/7/2012	12/17/2012	Quorum: 75.58% Approval: 34.80%			
360	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Initial Ballot	12/11/2012	12/20/2012	Quorum: 84.50% Approval: 95.60%	Support 12/19/12		
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			
364	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012 in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
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		

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
375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013_in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards
383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.58% Approval: 97.18%	Support 3/14/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.52% Approval: 98.89%	Support 3/14/13		
385	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 81.33% Approval: 89.44%	Support 1/11/13		
386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard- NPCC will submit suggested improvements
390	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 23.84%	Oppose 4/23/13		Losses of large blocks of load are typically caused by coincident transmission contingencies. Excessive and uninformed adjustments made to generation in order to bring the ACE to zero may well lead to further transmission issues. NPCC will submit suggested improvements
391	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
392	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Recirculation Ballot	4/18/2013	4/29/2013	Quorum: 80.70% Approval: 88.15%	No Consensus 3/22/13		
395	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Successive ballot	5/15/2013	5/24/2013	Quorum: 81.25% Approval: 69.23%	Support 5/23/13		The Regional Standard Committee has not expressed any concerns of significance that would warrant a ballot to reject, therefore the RSC recommends a yes vote, "Affirmative", to accept the standard
396	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Non-binding Poll	5/15/2013	5/24/2013	Quorum: 80.17% Approval: 61.11%			
397	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	6/24/2013	7/3/2013	Quorum: 77.65% Approval: 52.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	6/24/2013	7/3/2013	Quorum: 77.12% Approval: 52.48%			

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
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%			
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%			

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413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	8/23/2013	9/3/2013	Quorum: 75.25% Approval: 34.46%	No Consensus 8/31/13		NPCC to support with comments The most contentious issues raised by RSC members was surrounding the Control Center definition and the potential to vastly expand those needing training subject to the standard and compliance and that there was no need for a standard, rather, the FERC Directives should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 80.45% Approval: 34.24%			
415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	8/23/2013	9/3/2013	Quorum: 81.89% Approval: 43.79%	Oppose 8/31/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, lacks clarity, missing measures, quality, and other substantive issues. NPCC will be submitting detailed comments to address these issues. The RSC does not believe it would be beneficial to support the standard at this point as the next step, if it fails the initial ballot, would still require an additional ballot prior to moving to recirculation due to the substantive changes that are needed for the next revision. NPCC will be submitting helpful comments to NERC and supporting the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 79.95% Approval: 44.23%			
417	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Ballot	8/26/2013	9/4/2013	Quorum: 82.29% Approval: 41.24%	Support 8/31/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 79.66% Approval: 40.00%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Ballot	8/26/2013	9/4/2013	Quorum: 81.96% Approval: 55.76%	Support 8/31/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 80.35% Approval: 58.97%			
421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	8/26/2013	9/4/2013	Quorum: 78.68% Approval: 66.11%	Support 8/31/13		
426	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Final Ballot	9/4/2013	9/13/2013	Quorum: 85.93% Approval: 90.83%	Support 8/5/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Ballot	9/6/2013	9/16/2013	Quorum: 76.15% Approval: 58.23%	No Consensus 9/12/13		
423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Non-binding Poll	9/6/2013	9/16/2013	Quorum: 75.69% Approval: 59.66%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Final Ballot	9/11/2013	9/20/2013	Quorum: 91.64% Approval: 98.61%	Support 3/14/13		

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425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Final Ballot	9/11/2013	9/20/2013	Quorum: 90.98% Approval: 98.92%	Support 3/14/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.58% Approval: 88.75%	Support 10/16/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 75.89% Approval: 90.04%			
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Final Ballot	10/16/2013	10/25/2013	Quorum: 85.71% Approval: 85.38%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	10/18/2013	10/29/2013	Quorum: 75.83% Approval: 72.55%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	10/25/2013	11/4/2013	Quorum: 86.90% Approval: 91.95%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	10/25/2013	11/7/2013	Quorum: 76.67% Approval: 58.24%	No Consensus 11/1/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	11/1/2013	11/12/2013	Quorum: 76.23% Approval: 56.48%	Support 11/11/13		
434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Initial Ballot	11/4/2013	11/13/2013	Quorum: 76.12% Approval: 67.35%	Support 11/5/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-006-4	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 75.58%	Support 11/5/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-009-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 68.40%	Support 11/5/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 58.03%	Support 11/5/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-011-1	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.52% Approval: 71.35%	Support 11/5/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Initial Ballot	11/4/2013	11/15/2013	Quorum: 76.42% Approval: 77.82%	Support 11/5/13		
440	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Final Ballot	11/8/2013	11/18/2013	Quorum: 81.68% Approval: 74.34%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Additional Ballot	11/8/2013	11/20/2013	Quorum: 81.69% Approval: 82.97%	No Consensus 8/26/13		
442	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.05% Approval: 73.46%	Support 8/31/13		
443	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.84% Approval: 69.42%	Support 8/31/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	11/13/2013	11/22/2013	Quorum: 80.54% Approval: 57.59%	Support 8/31/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	11/15/2013	11/25/2013	Quorum: 80.81% Approval: 69.43%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	11/15/2013	11/25/2013	Quorum: 81.06% Approval: 66.09%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	12/2/2013	12/12/2013	Quorum: 75.29% Approval: 64.24%	No Consensus 12/9/13	Affirmative	
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	

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453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative		
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative		
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative		
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative		
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative		
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative		
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative		
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative		
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14	
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative		
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative		
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative		
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative		
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative		
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14	
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative		
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative		
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--		
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain		
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative		
473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-4, VAR-002-3	Final Ballot	4/23/2014	5/5/2014	Quorum: 83.84% Approval: 88.26%	Support--4/10/14	Affirmative		
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	5/1/2014	5/5/2014	Quorum: 92.53% Approval: 85.61%	Support--4/23/14	Abstain		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	5/6/2014	5/15/2014	Quorum: 85.79%/79.08% Approval: 86.28%/78.81%	No Consensus--5/15/14	Reject		
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative		

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[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	[illegible]	Affirmative Negative Affirmative Affirmative	
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative	
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29% Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14		
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14		
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative	
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative	
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative	
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative	
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative	
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative	
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing -	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	

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
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		

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11

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13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11
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	

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
26.	N/A	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	CAN-0029 PRC-004-1 R1, R2 and R3		5/20/11	6/10/11	
27.	N/A	CAN-0030--Draft CAN-0030 Attestations	CAN-0030 Attestations		5/20/11	6/10/11	
28.	N/A	CAN-0039--Draft CAN-0039 DOE Form 407	CAN-0039 DOE Form 407		5/20/11	6/10/11	
29.	Project 2010-05.1	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)			6/10/11	7/11/11	
30.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		6/15/11	7/15/11	Yes 7/15/11
31.	Project 2010-07	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards		6/17/11	7/17/11	Yes 7/15/11
32.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		6/15/11	8/1/11	Yes 8/1/11
33.	NERC RoP	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Appendices 4B and 4C		6/30/11	8/15/11	
34.	N/A	Compliance Application Notice (CAN) Process	CAN Process		8/15/11	9/6/11	Yes 9/6/11
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	

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
37.	NERC RSDP	NERC 2012-2014 Reliability Standards Development Plan	2012-2014 RSDP		9/12/11	9/26/11	Yes 9/26/11
38.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		8/15/11	9/28/11	Yes 9/28/11
39.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	BES Definition		8/26/11	10/10/11	Yes 10/10/11
40.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Technical Principles for Demonstrating BES Exceptions	Technical Principles for Demonstrating BES Exceptions		8/26/11	10/10/11	Yes 10/10/11
41.	N/A	New CAN Template, five DRAFT CANs for Industry review and CANs Status posted to NERC Compliance's Web site.	CANs		9/23/11	10/14/11	Yes 10/14/11
42.	RoP	Proposed Changes to NERC Rules of Procedure and All Appendices			9/2/11	10/17/11	
43.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	RoP Section 509, Section 1703 and Appendix 5C		9/13/11	10/27/11	Yes 10/27/11
44.	N/A	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	CAN-0010 Definition of Annual		10/10/11	10/31/11	Yes 10/31/11
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

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
49.	N/A	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN-0022 VAR-002-1.1b R1 and R3		10/10/11	10/31/11	
50.	N/A	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN-0024 CIP-002, R3		10/10/11	10/31/11	Yes 10/31/11
51.	N/A	CAN-0026--TOP-006 R3 Protection Relays	CAN-0026 TOP-006, R3		10/10/11	10/31/11	Yes 10/31/11
52.	N/A	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN-0028 TOP-006-1, R1.2		10/10/11	10/31/11	
53.	N/A	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002		10/19/11	11/9/11	
54.	N/A	CAN-0030--Attestations	CAN-0030		10/19/11	11/9/11	
55.	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	MOD-028, R3.1		10/3/11	11/16/11	Yes 11/16/11
56.	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Interpretation of COM-002-2, R2		10/4/11	11/18/11	Yes 11/18/11
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

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
64.	N/A	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	CAN-0027 TOP-003, R2		11/22/11	12/14/11	
65.	NERC RoP	Proposed Changes to the NERC Rules of Procedure and Associated Appendices			11/7/11	12/22/11	
66.	NERC RoP	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011			11/22/11	12/22/11	
67.	Regional Standard	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		11/22/11	12/22/11	
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	

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	
75.	N/A	NERC Functional Model Demand Response Functions and Entities	NERC Functional Model		2/13/12	3/14/12	
76.	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 for WECC	Interpretation of CIP-004-1		2/8/12	3/23/12	Yes 3/23/12
77.	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Interpretation of CIP-002-1, R3		2/8/12	3/23/12	Yes 3/23/12
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	

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86.	Project 2008-06	Project 2008-06 - Cyber Security Order 706 Version 5 CIP	CIP-002 and CIP-003 - Comment Form A		4/12/12	5/21/12	Yes 5/20/12
			CIP-004 thru CIP-007 - Comment Form B		4/12/12	5/21/12	Yes 5/20/12
			CIP-008 thru CIP-011 - Comment Form C		4/12/12	5/21/12	Yes 5/20/12
			Definitions and Implementation Plan - Comment Form D		4/12/12	5/21/12	Yes 5/20/12
87.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		4/25/12	5/24/12	Yes 5/24/12
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

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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
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

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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
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	

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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	
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

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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
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

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150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13

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163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13
169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13
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

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176	Project 2009-03	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2.1b EOP-002-3.1 EOP-003-2	5-year review	8/6/13	9/19/13	Yes 9/19/13
177	Project 2012-09	Project 2012-09 IRO Five-Year Review	IRO-003-2 IRO-004-2 IRO-005-4 IRO-006-5 IRO-006-East IRO-008-1 IRO-009-1 IRO-010-1a	5-year review	8/7/13	9/20/13	Yes 9/20/13
178	Project 2008-02	Project 2008-02 Undervoltage Load Shedding	Revised SAR	Informal	9/10/13	10/9/13	Yes 10/9/13
179	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	9/4/13	10/18/13	Yes 10/18/13
180	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition	Formal	9/27/13	10/28/13	Yes 10/28/13
181	Project 2007-02	Project 2007-02 Operating Personnel Communications Protocols	COM-002-4	Formal	10/21/13	11/7/13	Yes 11/4/13
182	Project 2010-01	Project 2010-01 Training	PER-005-2	Formal	9/27/13	11/12/13	Yes 11/12/13
183	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	Various INT Standards	Formal	9/30/13	11/13/13	Yes 11/13/13
184	Project 2012-05	Project 2012-05 ATC Revisions (MOD A)	MOD-001-2	Formal	10/4/13	11/20/13	Yes 11/18/13
185	Project 2010-03	Project 2010-03 Modeling Data (MOD B)	MOD-032-1, MOD-033-1	Formal	10/07/13	11/20/13	
186	Project 2010-04	Project 2010-04 Demand Data (MOD C)	MOD-031-1	Formal	10/09/13	11/22/13	Yes 11/22/13
187	Project 2013-04	Project 2013-04 Voltage and Reactive Control	VAR-001-4, VAR-002-3	Formal	10/11/13	11/25/13	Yes 11/25/13
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

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191	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-027	Formal	11/04/13	12/18/13	Yes 12/18/13
192	Project 2014-01	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	SAR	Formal	11/20/13	12/19/13	Yes 12/19/13
193	Project 2010-01	Project 2010-01 Training - PER-005-2	PER-005-2	Formal	12/4/13	1/22/14	Yes 1/17/14
194	Project 2010-03	Project 2010-03 Modeling Date - MOD B	MOD-033-1	Formal	12/6/13	1/22/14	Yes 1/21/14
195	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	INT-004-3 INT-010-2	Formal	1/10/14	1/24/14	Yes 1/22/14
196	Project 2007-02	Project 2007-02 Operating Personnel	COM-002-4	Formal	1/22/14	1/31/14	Yes 1/31/14
197	Project 2014-02	Project 2014-02 Standard Authorization Request – Cyber Security Standards	CIP SAR	Informal	1/17/14	2/18/14	Yes 2/18/14
198	2014 Work Plan	2014 Work Plan for NERC Reliability Standards Development	2014 Work plan			2/21/13	Yes 2/21/14
199	Project 2010-17	Project 2010-17 Definition of Bulk Electric System - Phase 2	BES	Informal	1/29/14	2/27/14	Yes 2/27/14
200	Project 2010-05.1	Project 2010-05.1 Protection System: Phase 1 (Misoperations) - PRC-004-3	PRC-004-3	Formal	1/17/14	3/11/14	Yes 3/2/14
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

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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
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

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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 Development Plan		Informal		7/21/14	Yes 7/21/14
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14

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		BAL-006					
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
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	Formal	09/03/14	10/17/14	Yes 10/17/14

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			CIP-010-X CIP-011-X				
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 for Dispersed Generation Resources	PRC-001-1.1 PRC-019-2 PRC-024-1	Formal	11/05/14	12/23/14	Yes 12/22/14
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15
255	Project 2014-	Project 2014-01	PRC-005-5	Informal	12/22/14	1/20/15	Yes

RSC Meeting #15-5, Agenda Item 6.3: Comment History

(As of 11/23/2015)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	01	Standards Applicability for Dispersed Generation Resources					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
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	SAR	Informal	4/16/15	5/19/15	Yes 5/19/15

RSC Meeting #15-5, Agenda Item 6.3: Comment History

(As of 11/23/2015)

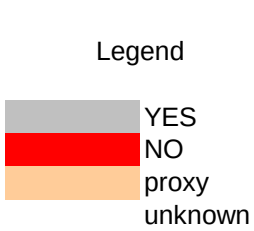
Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Directives					
271	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems – RAS	PRC-012-2	Informal	4/30/15	5/20/15	Yes 5/20/15
272	Project 2015-03	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3 FAC-011-3 FAC-014-2	Formal	5/4/15	6/17/15	Yes 6/17/15
273	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	IRO-006-East-2 IRO-009-2	Formal	5/21/15	7/8/15	Yes 7/8/15
274	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	PRC-005-3	Formal	6/11/15	7/10/15	Yes 7/10/15
275	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generations Resources	PRC-004-2.1 PRC-005-2 PRC-005-3	Informal	6/12/15	7/13/15	Yes 7/13/15
276	Project 2015-07	Project 2015-07 Internal Communications Capabilities	COM-001-2	Informal	6/11/15	7/15/15	Yes 7/15/15
277	Project 2015-04	Alignment of Terms	Glossary Terms	Formal	6/12/15	7/23/15	Yes 7/23/15
278	Project 2009-02	Real-time Monitoring and Analysis Capabilities	SAR	Formal	7/16/15	8/17/15	Yes 8/17/15
279	NERC 2016-2018	Reliability Standards Development Plan	Development Plan	Formal	7/16/15	8/17/15	Yes 8/17/15
280	Project 2015-08	Emergency Operations	EOP-004-2 EOP-005-2 EOP-006-2 EOP-008-1	Informal	7/21/15	8/19/15	Yes 8/19/15
281	Project 2010-14.1	Phase 1 of Balancing Authority Reliability-based Controls	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15
282	Project 2010-14.2.2	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-	MOD-031 FERC	MOD-031-2	Formal	7/31/15	9/18/15	Yes

RSC Meeting #15-5, Agenda Item 6.3: Comment History

(As of 11/23/2015)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	04.1	Order No. 804 Directives					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

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."


Legend
YES
NO
proxy
unknown

12/1/2015
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	1. Determine Quorum			2. Vote/Ballot Recording						
NPCC Registered Members		**In Attendance**	**By Proxy**	**Affirmative**	**Negative**	**Abstain**				
		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)				
Sector 1, Transmission Owners	**19**	**15**	**0**	**14**	**0**	**1**		**Primary**	**Alternate**	**Proxy**

	1. Determine Quorum			2. Vote/Ballot Recording						
NPCC Registered Members		**In Attendance**	**By Proxy**	**Affirmative**	**Negative**	**Abstain**				
		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)				
Sector 2, Reliability Coordinators	**5**	**5**	**0**	**5**	**0**	**0**		Primary	Alternate	Proxy

	1. Determine Quorum		2. Vote/Ballot Recording						
NPCC Registered Members	**In Attendance**	**By Proxy**	**Affirmative**	**Negative**	**Abstain**				
	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)				
Sector 3, TDUs, Dist. And LSE	**20** **13**	**0**	**12**	**0**	**1**		Primary	Alternate	Proxy

	1. Determine Quorum			2. Vote/Ballot Recording						
NPCC Registered Members		**In Attendance**	**By Proxy**	**Affirmative**	**Negative**	**Abstain**				
		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)				
Sector 4, Generator Owners	**22**	**17**	**0**	**17**	**0**	**0**		Primary	Alternate	Proxy

	1. Determine Quorum			2. Vote/Ballot Recording						
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**			
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)			
Sector 5, Marketers, Brokers, Aggragators	**14**	**8**	**0**		**8**	**0**	**0**	Primary	Alternate	Proxy

NPCC Annual Meeting of Members
November 30, 2011
Marriott Bloor Yorkville Toronto

12/1/2015
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NPCC Registered Members	1. Determine Quorum			2. Vote/Ballot Recording		
		In Attendance (denote w/ 1)	By Proxy (denote w/ 1)	Affirmative (denote w/ 1)	Negative (denote w/ 1)	Abstain (denote w/ 1)
Sector 6, State and Provincial Reg. and Govt. Authorities	**6**	**4**	**0**	**4**	**0**	**0**
Long Island Power Authority	1	1		1		
Maine Public Utilities Commission	1	1		1		
Massachusetts Attorney General	1	1		1		
New Hampshire Public Utilities Commission	1					
New York Power Authority	1	1		1		
New York State Department of Public Service	1					
Vermont Department of Public Service						

NPCC Annual Meeting of Members
November 30, 2011
Marriott Bloor Yorkville Toronto

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NPCC Annual Meeting of Members
November 30, 2011
Marriott Bloor Yorkville Toronto

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NPCC Annual Meeting of Members
November 30, 2011
Marriott Bloor Yorkville Toronto

Primary	Alternate	Proxy
Robert Ganley	Richaed Zambratto	
Margrethe Heimgartner	Jason Rauch	
Federick Plett		
George McCluskey		
Arnold Schuff	Lawrence Hochberg	
Leka Gjonaj	Edward Schrom	

	1. Determine Quorum			2. Vote/Ballot Recording						
NPCC Registered Members		**In Attendance**	**By Proxy**	**Affirmative**	**Negative**	**Abstain**				
		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)				
Sector 7, Sub Regional Rel. Councils, REs and Others	**13**	**7**	**0**	**7**	**0**	**0**		**Primary**	**Alternate**	**Proxy**

Determine Electronic Quorum

Sector	Sector Name	Total Registered	In Attendance	By Proxy	Total Represented	Sector % Attending
1	**Transmission Owners**	19	15	0	15	0.79
2	**Reliability Coordinators**	5	5	0	5	1.00
3	**TDUs, Dist. And LSE**	20	13	0	13	0.65
4	**Generator Owners**	22	17	0	17	0.77
5	**Marketers, Brokers, Aggragators**	14	8	0	8	0.57
6	**Customers- large and small**	6	4	0	4	0.67
7	**State and Provincial Reg. and Govt. Authorities**	13	7	0	7	0.54
		99	69	0	69	

Electronic Vote Quorum= at least 2/3 of the Total Registered

Quorum Present? **YES**

Determine if Motion or Item Passes

Sector	Sector Name	Total Registered	Sector % Attending	Affirmative # of Votes	Affirmative Fraction	Negative # of Votes	Negative Fraction	Abstain # of Votes	Votes Cast Total (-Abstentions)	Sector has Voted(1-Y, 0-N)
1	**Transmission Owners**	19	0.79	14	1.000	0	0.000	1	14	1
2	**Reliability Coordinators**	5	1.00	5	1.000	0	0.000	0	5	1
3	**TDUs, Dist. And LSE**	20	0.65	12	1.000	0	0.000	1	12	1
4	**Generator Owners**	22	0.77	17	1.000	0	0.000	0	17	1
5	**Marketers, Brokers, Aggragators**	14	0.57	8	1.000	0	0.000	0	8	1
6	**Customers- large and small**	6	0.67	4	1.000	0	0.000	0	4	1
7	**State and Provincial Reg. and Govt. Authorities**	13	0.54	7	1.000	0	0.000	0	7	1
	Totals	99		67	7.000	0	0.000	2	67	7

Sum of Affirmative/Number of Sectors that Voted
MUST BE AT LEAST 2/3 to pass 1.000

Did MOTION PASS? **PASS**

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

PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance DT Roster

Self-Nominations			
	Name:	**Company:**	**Qualifications:**
1	Vincent Morissette	Hydro Quebec	I am an engineer in short term planning department for Hydro-Québec TransÉnergie since 2010. I have been involved in many dynamic studies, including frequency stability and UFLS settings, and RSAW completion for compliance with NERC standards, including PRC-006-1. As the Hydro-Québec TransÉnergie representative on the NPCC SS-38 Working Group on Inter-Area Dynamic Analysis, I was involved in the 2014 Assessment of NPCC Underfrequency Load Shedding Program for year 2018. I am also SME (Subject Matter Expert) for the Planning Coordinator for the two standards related to UFLS (PRC-006-1 and PRC-006-NPCC-1).
2	Jeannette Gauthier	Hydro Quebec	I am an electrical engineer with almost 20 years' experience in planning and operations in transmission, generation and distribution at Hydro-Quebec. (As a transmission planner I even conducted simulations of under-frequency load-shedding.) I also have 5 years' experience outside Hydro-Quebec in a regulatory environment. I have testified before various forums (including the Régie de l'énergie) as an expert witness and drafted many technical and legal documents albeit in French. For the past year I have worked for the Quebec RC as a compliance officer. My experience regarding reliability standards includes event analysis, participation in mock audits and preparation for NPCC audit, submitting and providing follow-up on self-reports and mitigation plans, development and implementation of the internal compliance program, NPCC and NERC workshops and webinars, actively commenting standards and RSAWs under development and supporting implementation plans for new and revised standards. More specifically in relation to the PRC-006-3 Drafting team, I have counseled the SMEs (PC and TO) with regard to compliance and implementation of PRC-006 and PRC-006-NPCC. Aside from submitting my nomination to revise the Quebec Variance of PRC-006, I request NPCC's authorization to act as an observer on PRC-006-NPCC-2 Drafting Team.
3	Philippe Cadieux	Hydro Quebec	Philippe is an engineer in operation planning department for Hydro Quebec since 2013, and have worked for the long term transmission planning group at Hydro Quebec from 2007 to 2013. He has been involved in many dynamic and stability studies, including voltage and frequency stability.
4	Dean Latulipe	National Grid	21 years in Transmission Planning at National Grid. Chairman SS-38 working group. Conducted UFLS study for New England in 2014.

5	Daniel Kidney	NPCC Compliance Staff	NPCC Compliance Staff. Daniel has been a member of the Compliance Enforcement staff at NPCC since 2014. Prior to joining NPCC, he was employed as a Transmission Planner at Central Maine Power.
6	Ruida Shu	NPCC Standards Staff	NPCC Standards Staff. Ruida Shu has 8+ years of experience in Distribution, Transmission, SCADA, Construction, Daily Electric Operations, Facility Maintenance, Security, DOE/FEMA/APPA Grant Projects, Safety, Compliance and Reliability Standards.

REGIONAL STANDARDS COMMITTEE

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Sector (3) - Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs")

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Sector (4) - Generator Owners

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Sector (5) - Marketers, Brokers and Aggregators

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VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
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November 20, 2015

Re: Informational Filing of the North American Electric Reliability Corporation in Response to the Federal Energy Regulatory Commission's November 20, 2014 Order, Docket No. RR14-5-000

Dear Ms. Bose,

The North American Electric Reliability Corporation hereby submits this Informational Filing in response to the Federal Energy Regulatory Commission's Order issued November 20, 2014, in Docket No. RR14-5-000.

Please contact the undersigned if you have any questions concerning this filing.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston
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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. RR14-5-000**

INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO THE FEDERAL ENERGY REGULATORY COMMISSION'S NOVEMBER 20, 2014 ORDER

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November 20, 2015

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APPENDIX A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**)** **)**	**Docket Nos. RR14-5-000**

INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO THE FEDERAL ENERGY REGULATORY COMMISSION'S NOVEMBER 20, 2014 ORDER

On July 21, 2014, the North American Electric Reliability Corporation ("NERC") submitted its second Electric Reliability Organization ("ERO") performance assessment to demonstrate its accomplishments and continued satisfaction of the criteria for certification as the nation's ERO. In that assessment, NERC also evaluated each Regional Entity's effectiveness in implementing delegation-related activities and addressed stakeholder comments on the ERO Enterprise's performance.[1] On November 20, 2014, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued the *Order on the Electric Reliability Organization's Five-Year Performance Assessment* ("November 2014 Order"). In the November 2014 Order, the Commission accepted the performance assessment, finding that NERC and each of the eight Regional Entities continue to satisfy the statutory and regulatory criteria for operation as the ERO Enterprise.

[1] The "ERO Enterprise" refers to the informal affiliation of NERC and the eight Regional Entities for the purpose of coordinating goals, objectives, metrics, methods and practices across statutory activities. The operation of the ERO Enterprise does not conflict with obligations of each organization through statutes, regulations, and delegation agreements. The eight Regional Entities are: (i) Florida Reliability Coordinating Council, Inc. ("FRCC"); (ii) Midwest Reliability Organization ("MRO"); (iii) Northeast Power Coordinating Council, Inc. ("NPCC"); (iv) ReliabilityFirst Corporation ("RF"); (v) SERC Reliability Corporation ("SERC"); (vi) Southwest Power Pool Regional Entity ("SPP"); (vii) Texas Reliability Entity, Inc. ("Texas RE"); and (viii) Western Electricity Coordinating Council ("WECC").

Pursuant to Paragraph 71 of the November 2014 Order, the Commission also directed NERC to submit this Informational Filing to address "how it is improving coordinated operations and [to] describe any efforts it has made to improve such operations, including, but not limited to the 11 action items described in [the ERO Enterprise Operating Model]." The Commission directed NERC to address various topics relating to tracking of Reliability Standard projects, development of performance metrics measuring consistency, coordination and efficiency within the ERO Enterprise, and improvements to future performance assessments.

This Informational Filing is organized as follows:

- **Section I – Performance Measures for the ERO Enterprise** – NERC describes the following three ERO Enterprise performance measures: (1) ERO Enterprise and corporate metrics for the ERO; (2) Regional Entity performance metrics; and (3) reliability metrics for the performance of the Bulk Power System;[2]

- **Section II – ERO Enterprise Decision-Making and Communication** – NERC describes recent efforts to enhance the ERO Enterprise decision-making process and to enhance the ability of ERO Enterprise senior leadership to continue setting the direction and policy of the ERO Enterprise;[3]

- **Section III – Reliability Standards** – NERC examines efforts to track Reliability Standards completion and to reflect the complexity and urgency of Reliability Standards projects;[4]

- **Section IV – Enforcement** – NERC addresses efficiency and transparency in NERC's enforcement processes;[5]

- **Section V – ERO Enterprise Information Technology and Data Sharing** – NERC describes efforts to improve technological infrastructure across the ERO Enterprise.[6]

[2] *See* Operating Model Action Items 2, 3, 4, 5, 8, and 9; *see also* November 2014 Order at PP 52-54, 56, 70-74.

[3] *See* Operating Model Action Items 6, 7, 10, and 11.

[4] *See* November 2014 Order at PP 63-65.

[5] *See* November 2014 Order at PP 38-39, 72.

[6] *See* Operating Model Action Item 9.

I. PERFORMANCE MEASURES FOR THE ERO ENTERPRISE

A. Overview of Performance Measures

The ERO Enterprise has a distributed governance structure ensuring that the ERO has a robust and technical understanding of both the regional and interconnected aspects of the Bulk Power System. Given this structure, collaboration is necessary to execute statutory functions and to mitigate reliability risks to the Bulk Power System. In the ERO Enterprise Operating Model, NERC and the Regional Entities outline a plan to coordinate so as to achieve excellence in their execution of statutory functions and delegation-related activities. An important component of this plan is the development and publication of "performance measures focused on Bulk Power System reliability outcomes and effectiveness of the statutory programs."[7] NERC contemplates three sets of performance measures – (1) ERO Enterprise and corporate metrics assessing the performance of NERC program areas; (2) Regional Entity performance metrics assessing the Regional Entities' execution of delegation-related activities; and (3) reliability metrics assessing the performance of the Bulk Power System. Each performance measure is described below:

(1) NERC publishes ERO Enterprise and corporate metrics, which are high-level performance goals for ERO program areas, on a rolling, three-year basis in the ERO Enterprise Strategic Plan ("Strategic Plan"). For each such metric, NERC identifies (A) a measure of success, (B) a minimum threshold for performance, and (C) a performance target. NERC updates these metrics on an annual basis in concert with each iteration of the Strategic Plan.

(2) While the ERO's corporate metrics and reliability metrics are in place and updated regularly, the Regional Entity performance metrics are under development pursuant to

[7] *See* Operating Model Action Item 5; *see also* Section 8(a)(i) of the Regional Delegation Agreements.

an enhanced and formalized oversight program. Pursuant to this enhanced program, described in more detail below, NERC is developing performance metrics to evaluate the Regional Entities' performance of each delegation-related activity, except Reliability Standards.[8] NERC plans to have all performance metrics finalized by the close of calendar year 2017.

(3) NERC publishes reliability metrics in its annual state of reliability report in which NERC tracks the performance of the Bulk Power System. NERC revises these metrics as needed to reflect new and evolving risks to the Bulk Power System, based on emerging trends and areas of particular reliability focus. For example, in the *2015 State of Reliability Report*, NERC described two groups of reliability metrics in development. One group of metrics is based on noncompliance data and the other group is based on Bulk Power System performance security metrics.[9] The reliability metrics based on noncompliance data will track reported instances of noncompliance with an observed reliability impact and reflect trends associated with the risk of noncompliance. The reliability metrics based on Bulk Power System performance security metrics will define lagging and leading indicators for cyber and physical security performance as they relate to reliable Bulk Power System operation.

B. Regional Entity Performance Metrics and the ERO Enterprise Oversight Program

Under NERC's enhanced oversight program, NERC will systematically track and publish performance metrics for each delegation-related activity performed by each Regional Entity.

[8] NERC is not developing an oversight plan for Reliability Standards given the ERO Enterprise's increasing focus on continent-wide Reliability Standards.

[9] The five performance security metrics are: (i) reportable cyber security incidents; (ii) reportable physical security events; (iii) ES-ISAC membership; (iv) industry-sourced information sharing; and (v) global cyber vulnerabilities.

NERC is developing these performance metrics through working groups consisting of senior-level program area employees from NERC and the Regional Entities.

In 2015, NERC developed a framework for the enhanced oversight program (referred to hereafter as the "Oversight Framework") which outlines NERC's path towards more coordinated implementation of delegation-related activities through unified systems, processes and procedures. In the Oversight Framework, NERC highlights that the Oversight Plan for each program area must specify the following:

(1) assignment of NERC and Regional Entity roles and responsibilities contemplated for each program area that is consistent with the NERC Rules of Procedure, the Regional Delegation Agreements, and Commission orders;

(2) required knowledge, skills and training expectations to carry out responsibilities for key roles in each program area;

(3) list of performance metrics which take into account the risk-based approaches as well as a schedule for measuring and posting such metrics;

(4) description of monitoring activities; and,

(5) feedback mechanisms to enable Regional Entities to improve program performance to meet NERC's expectations.[10]

C. Development Schedule for Oversight Plans

NERC developed a prioritized and staggered three-year schedule to develop Oversight Plans for seven delegation-related activities in the Regional Delegation Agreements.[11] Under this

[10] *See* Operating Model Action Items 2a, 2c, and 8.

[11] These seven statutory delegation-related activities addressed in the oversight program are: (i) compliance monitoring; (ii) enforcement; (iii) organization registration; (iv) reliability assessment; (v) performance analysis; (vi) event analysis; and (vii) situation awareness.

schedule, NERC will complete Oversight Plans and performance metrics for compliance monitoring, registration and enforcement by the end of the 2015 calendar year.[12] NERC expects to complete Oversight Plans for performance analysis, event analysis and situation awareness by the end of the 2016 calendar year. Finally, NERC plans to complete Oversight Plans for reliability assessment by the end of the 2017 calendar year. Once complete, NERC will post the performance metrics from each program area on the NERC website. NERC will also include an analysis of the implementation of these performance metrics in the 2019 ERO performance assessment.

II. ERO ENTERPRISE DECISION-MAKING AND COMMUNICATION

A. ERO Executive Management Group

In the Operating Model, NERC calls for the ERO Executive Management Group ("ERO EMG") to continue setting the direction and policy for the ERO Enterprise.[13] Through a collaborative process with the Regional Entities, NERC develops policies and procedures to guide the Regional Entities' implementation of delegation-related activities. The ERO EMG leads this collaborative process with input from working groups and task forces, such as the ERO Legal Group, the ERO Finance Group, and the ERO Compliance Monitoring, Registration and Enforcement Groups, which are directly accountable to the ERO EMG. If collaboration is unsuccessful, the NERC President, pursuant to the Regional Delegation Agreements, has the authority to issue directives concerning performance of delegation-related activities.

Over the past year, NERC, under the oversight of the Enterprise-wide Risk Committee ("EWRC"), and the ERO EMG have been developing a program, called the ERO Enterprise Risk

[12] *See* Section 8 of the Pro Forma Regional Delegation Agreement.

[13] Operating Model Action Item 6.

Management Program.[14] The purpose of the program is to identify priority risks to the ERO Enterprise and to implement management controls and mitigation activities. This program provides another example of ongoing efforts to improve ERO Enterprise consistency and coordinated operations. An ERO EMG working group (the "Risk Management Group") is responsible for developing and implementing this program. The Risk Management Group is comprised of representatives from the Regional Entities and NERC's Internal Audit and Corporate Risk Management department. The EWRC of the NERC Board of Trustees oversees the program and reviews any analysis produced by the Risk Management Group, after review by the ERO EMG.

B. Canadian Outreach

In the Operating Model, NERC and the Regional Entities recognize the importance of coordinating outreach efforts to Applicable Governmental Authorities in both the U.S. and Canada.[15] As of the date of this filing, eight provincial governments,[16] plus the National Energy Board of Canada, have implemented a mandatory reliability framework based on NERC Reliability Standards. The role of NERC and the Regional Entities is recognized in these Canadian jurisdictions through legislation, regulation and various agreements including memoranda of understanding and data sharing agreements. These agreements between NERC, the applicable Regional Entity, and the relevant provincial entity govern the operational relationships and respective duties of each party within the mandatory reliability framework of an individual

[14] *See e.g.*, Agenda Enterprise-wide Risk Committee Meeting Package, dated February 10, 2015 (including work plans reflecting activities such as "Coordinate with the Regional Entities to implement and report on the ERO Enterprise Risk Management Framework.").

[15] *See* Operating Model Action Item 11.

[16] (i) Alberta; (ii) British Columbia; (iii) Manitoba; (iv) New Brunswick; (v) Nova Scotia; (vi) Ontario; (vii) Québec; and (viii) Saskatchewan.

province. As these mandatory reliability frameworks have evolved, NERC and the Regional Entities have worked with Canadian provinces to amend and update existing agreements. For example, in September 2014, a revised agreement was executed between NERC, NPCC, and the Régie de l'énergie in Québec to revise mandates from the Régie to NERC and NPCC to implement monitoring of Reliability Standards in Québec. Similarly, in August 2015, NERC, MRO, and Saskatchewan Power Corporation entered into a revised memorandum of understanding to reflect the establishment of the legislated authority responsible for setting, monitoring, and enforcement of Reliability Standards in the Province of Saskatchewan. NERC and the applicable Regional Entities are discussing revisions to other agreements with the relevant provincial entities.

In further support of strengthening the outreach of the ERO, NERC created a Director of Canadian Affairs position to foster coordination on Canadian issues not only between NERC and the Regional Entities, but also between NERC and Canadian stakeholders, namely Canadian federal and provincial governmental agencies. The director works with Canadian stakeholders and the three Regional Entities with international footprints (NPCC, MRO, and WECC) to identify and leverage opportunities to strengthen the North American reliability framework. During the next assessment period, the director will work with Canadian stakeholders to strengthen the value of a common reliability framework.

III. RELIABILITY STANDARDS

A. Tracking Reliability Standards Projects

In the November 2014 Order, the Commission directed NERC to:

> [T]rack, on a going-forward basis, actual project completion times as compared to estimated time for completion at the outset of a given project . . .[and] incorporate these more granular measures into its

> future performance assessment filings, beginning in 2019, and post them as developed prior to 2019.[17]

Consistent with the Commission's directive, NERC is tracking actual project completion times, as well as important milestones (i.e., comment periods and ballots) during the development of projects, as compared to the estimated time for milestones and completion at the outset of a given project. For example, NERC maintains a publicly available Project Tracking Spreadsheet on its Reliability Standards webpage to enable transparent examination of actual project status over the course of a year in comparison to the initial projected estimates. NERC updates this spreadsheet periodically and retains older versions.[18] NERC has successfully worked to stagger expected completion dates for Reliability Standard updates to ensure that stakeholders and the NERC Board of Trustees have adequate time to fully review and comment prior to adoption. This staggering limits the accumulation of projects in the final quarter of each calendar year. Furthermore, NERC will develop a metric that compares actual project completion to estimated time for completion. NERC is also gaining experience on the time that it takes to develop specific types of Reliability Standards. This institutional knowledge will result in improvements to coordination between Reliability Standards development projects, a more graduated approach to Reliability Standards development, as well as better scheduling of posting, due to a better understanding of estimated time expectations. These efforts will afford industry more time to review Reliability Standards and should ultimately result in higher quality Reliability Standards. As stated above, the Reliability Standards department will refine the development schedules of projects by the close of the 2016 calendar year.

[17] November 2014 Order at P 64.

[18] *See*, *e.g.*, http://www.nerc.com/pa/Stand/Pages/default.aspx.

B. Interpretations

In the November 2014 Order, the Commission "encourage[d] NERC to explore ways to reduce the time needed to process a request for interpretation."[19] NERC's Reliability Standards development process is accredited by the American National Standards Institute ("ANSI"). As part of that accreditation, there is a requirement to have an interpretation process in place; however, ANSI does not specify what or how long the process should take. There is flexibility in how NERC may revise its process to reduce the time required to complete the interpretation and to continue to meet the ANSI requirement. NERC will continue to explore ways to reduce the time for processing requests for interpretation, while balancing reliability and ensuring a complete understanding of the questions raised.

C. Technical Input

In the November 2014 Order, the Commission "encourage[d] NERC's technical staff to provide feedback to the Reliability Standard drafting teams as early as possible in the drafting process so that the drafting team can consider NERC staff's unique insights, particularly prior to comment or ballot periods."[20] NERC confirms that its technical staff currently provides feedback to Reliability Standard drafting teams as early as possible in the drafting process, and is engaged in discussions well in advance of any ballot and comment period. They collaborate at each step of the process so that the drafting team can consider NERC staff's unique insights.

IV. ENFORCEMENT

A. Violation Processing

In the November 2014 Order, the Commission stated that it "expect[s] that violation

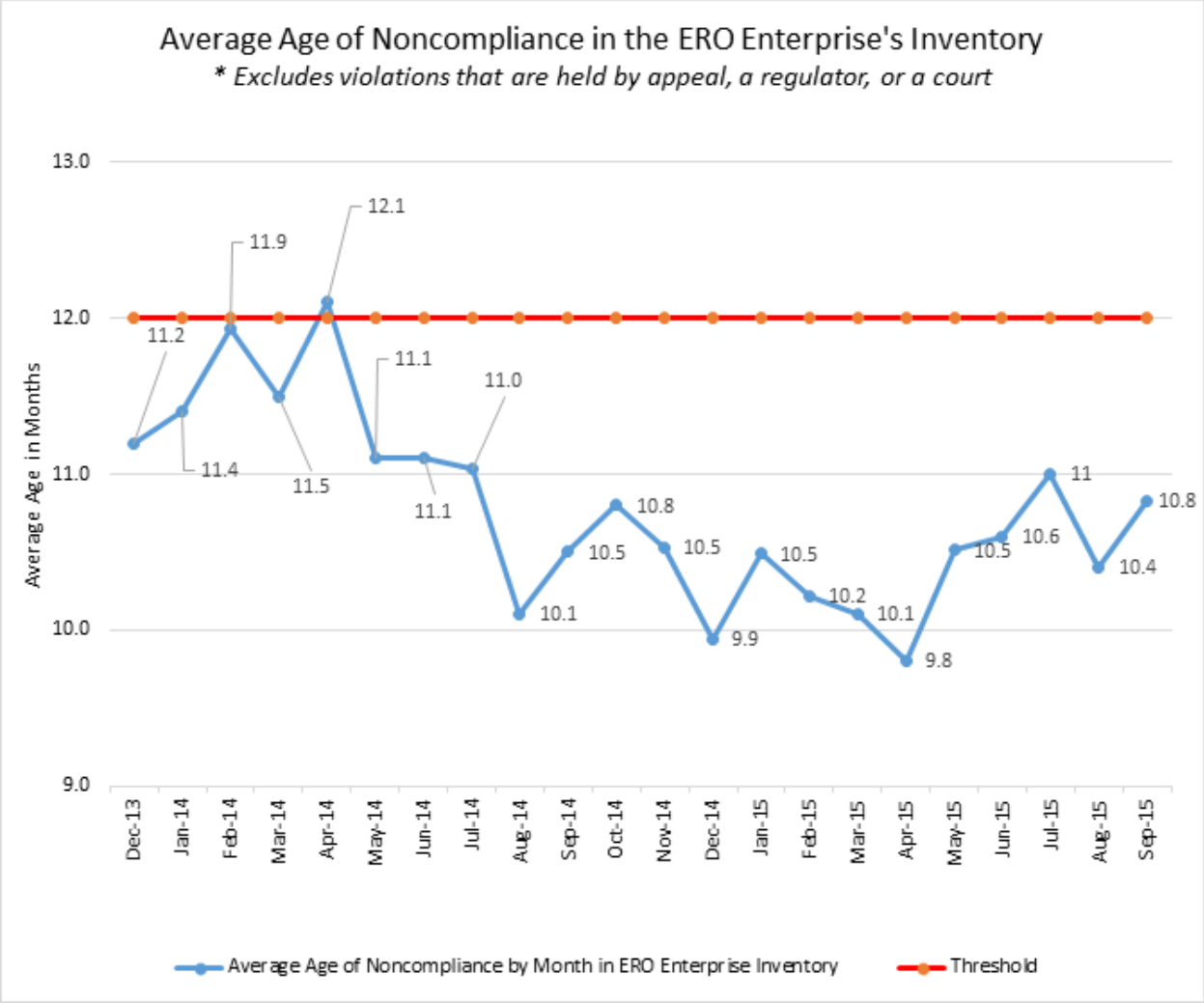
[19] November 2014 Order at P 63.

[20] *Id.*, at P 65.

processing times and the average violation age will continue to decline."[21] NERC's enforcement efforts continue to focus on efficiency and effectiveness in violation processing, balanced with ensuring reliability, quality, and fiscal responsibility. Since 2011, NERC and the Regional Entities have focused their enforcement efforts on noncompliance posing the greatest risk to reliability. For lesser risk noncompliance, the Compliance Monitoring and Enforcement Program has implemented processes that allow for more streamlined disposition. NERC strives to maintain an average violation age between 10 to 12 months for processing noncompliance and to manage the caseload. The following chart demonstrates that the average age of non-compliance has continued trending consistently downwards, exhibiting further improvement in processing times and the average violation age.[22] More complex cases, which are not appropriate for streamlined treatment, may affect such average timeframes. NERC continues to focus on timely mitigation of any outstanding risks regardless of the manner in which the noncompliance is addressed.

[21] *Id.*, at P 38.

[22] *Board of Trustees Compliance Committee Open Meeting*, *Agenda Item 6*, at pp. 22-23 (May 6, 2015), *available at*, http://www.nerc.com/gov/bot/BOTCC/Compliance%20Committee%202013/BOTCC%20Open%20Agenda%20Package%206%20May%202015.pdf.



B. Transparency in Enforcement

The Commission's November 2014 Order also supported NERC's recent efforts to increase efficiencies while maintaining transparency in enforcement processes, and stated that:

> NERC should continue to promote transparency in its enforcement programs, particularly as it moves forward with its Reliability Assurance Initiative, given the value of transparency in encouraging full and adequate mitigation practices and in providing assurance to the Commission, registered entities, and the public that the program is being fairly and consistently implemented across all regions. … we expect NERC to continue making information publicly available concerning possible non-compliance (other than those involving

> physical security or cybersecurity concerns) resolved through any and all processing methods.[23]

Consistent with the Commission's statement, NERC continues to promote transparency in enforcement processes. NERC posts on its website quarterly public reports on implementation of the risk-based Compliance Monitoring and Enforcement Program ("CMEP").[24] Specifically, NERC publicly files Notices of Penalty and Spreadsheet Notices of Penalty with the Commission. NERC also publicly posts Find, Fix, Track and Report determinations as well as Compliance Exceptions. NERC will also report on its evaluation of implementation of the risk-based CMEP to the Commission through an annual filing, beginning in February 2016. These efforts illustrate NERC's commitment to transparency and making information publicly available regarding non-compliance, consistent with regulations, the NERC Rules of Procedure, and potential physical security and cybersecurity concerns. NERC will continue to cooperate with Commission staff and share data and information, consistent with the Commission's expectation in the November 2014 Order.[25]

V. ERO ENTERPRISE INFORMATION TECHNOLOGY AND DATA SHARING

In the Operating Model, NERC identifies a need to develop core tools to support statutory functions of the ERO.[26] Over the past year, the ERO Enterprise has been collaborating on methods to improve data sharing and to enhance its infrastructure.[27] Given the ERO Enterprise's distributed

[23] November 2014 Order at P 72. "Reliability Assurance Initiative," *see* Docket No. RR15-2-000, was completed in 2014, and is considered part of the risk-based compliance monitoring and enforcement program.

[24] *See e.g., supra* n. 22.

[25] *See* November 2012 Order at P 38 (Commission regulations and the NERC Rules of Procedure apply to such data sharing).

[26] *See* Operating Model, at Action Items 8 and 9.

[27] The activities described here directly implement Action Item 9; however, because improved data sharing across an integrated platform is anticipated to enhance consistency, it also materially furthers the goals in Action Item 8 of the Operating Model.

governance model, some Regional Entities have differing information technology platforms and approaches for their delegation-related activities. NERC is working with the Regional Entities to develop a plan to replace these differing platforms, as appropriate. The ERO EMG formed a Technology Leadership Team ("TLT") to guide this transition as well as to identify the NERC and Regional Entity-specific information technology requirements, business needs, and priorities.

In the case of registration, NERC is exploring a centralized compliance registration service hosted at NERC.[28] The goal of this effort is to ensure both a consistent user experience for registered entities as well as a consistent experience for the ERO Enterprise so that the Regional Entities and NERC can access current and accurate registered entity information. In addition to registration, NERC and the Regional Entities are evaluating technology improvements for compliance monitoring and enforcement, including a possible move to a single platform. The ERO Enterprise currently uses three separate tools for these program areas.

In 2015, NERC undertook the following projects to support the ERO Enterprise's strategic vision for data sharing amongst NERC and the Regional Entities:

- **Reliability Assessment Data System ("RADS") –** The RADS system automates the tracking and consolidation of seasonal assessment data for the Long Term Reliability Assessment. Prior to this automation, NERC manually populated, consolidated, and evaluated the data submitted to NERC by the Regional Entities. The new RADS system allows for automatic upload of Excel spreadsheets, validates the data submitted, and tracks progress of the data submittal and acceptance process. This automation enables NERC staff to focus resources on data analysis rather than on data administration.

[28] *See Agenda Board of Trustees Package, Agenda Item 6.a.,* (May 7, 2015), *available at,* http://www.nerc.com/gov/bot/botquarterlyitems/Board_of_Trustees_Agenda_Package_May_7_2015.pdf.

- **The Events Analysis Management System ("TEAMS") –** The TEAMS project has improved the way NERC manages and classifies event information, and enables Regional Entities to submit voluntary event data provided by industry to NERC while maintaining their existing processes and forms. The Regional Entities and NERC can also view the same data, track the event process, and run reports, ensuring consistency of data and reporting.
- **Enterprise Reporting –** NERC uses data from the Generator Availability Data System ("GADS"), the Transmission Availability Data System ("TADS"), and the Demand Response Availability Data System ("DADS") to assess reliability trends and performance. NERC also highlights these applications in various publications and reports. NERC is replicating this data; currently hosted by a third party, to NERC-managed databases, and is in the process of making that data available to Regional Entities. This approach negates the need to obtain this information through a third party provider, and enhances the ability of both NERC and the Regional Entities to analyze this data efficiently. The longer-term ERO Enterprise reporting effort will move this and other data into an ERO Enterprise data warehouse, which is currently in its early stages of design.
- **Misoperations Information System ("MIS")** – The purpose of the MIS project is to enable consistent and reliable submission, processing and reporting of misoperations data from registered entities to NERC. This will be done via a centralized system and standardized template for performance analysis. The Regional Entities and NERC will be able to view the same data, track the submission process and run reports and analysis to ensure consistency of data and reporting and increase process efficiency.

VI. CONCLUSION

As detailed above, NERC is implementing many action items identified in the Operating Model as well as in the November 2014 Order to increase consistency and coordination across the ERO Enterprise. NERC will provide a further update on these items as well as additional undertakings from the first ERO five-year performance assessment in the 2019 ERO Performance Assessment.

Respectfully Submitted,

/s/ Nina H. Jenkins-Johnston

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Counsel for the North American Electric Reliability Corporation

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 Docket No. RR14-5-000.

Dated at Washington, D.C. this 20th day of November, 2015.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston
Nina H. Jenkins-Johnston

Counsel for the North American Electric Reliability Corporation

APPENDIX A

Appendix A: Actions Items from the Operating Model

Action Item 1 – NERC includes in its review of Regional Entity business plans adequacy of resources and alignment of the plans for achieving delegated function objectives and outcomes described in the three-year plan.

Action Item 2 – NERC, in collaboration with Regional Entities:

a) develops a comprehensive overarching design and set of controls, reporting requirements, and feedback mechanisms for each delegated statutory function, including the essential oversight elements listed above;

b) reevaluates its organizational structure and leadership qualifications necessary to provide effective design and oversight of statutory activities;

c) identifies functional qualifications for select delegated activities, such as auditors and investigators; and,

d) adopts risk-based approaches to monitoring performance of delegated functions and providing effective feedback and coaching to continuously improve overall ERO Enterprise performance;

Action Item 3 – Regional Entities:

a) work in a coordinated fashion to support NERC in the development of comprehensive functional program designs and controls;

b) adapt existing regional programs for delegated functions to conform with emerging program designs provided by NERC; and,

c) ensure Regional Entity staffs meet qualification and training requirements.

Action Item 4 – NERC and Regional Entities develop and maintain a joint three-year strategic plan for the ERO Enterprise describing the goals and deliverables for statutory functions and this plan should guide the development of each Regional Entity's annual business plans. Additional goals and deliverables that are complimentary or supplemental to the strategic plan may be developed at the Regional Entity level.

Action Item 5 – NERC and Regional Entities develop and transparently report results based on a common set of performance measures focused on bulk power system reliability outcomes and effectiveness of the statutory programs. These measures are considered in the performance management program at each entity.

Action Item 6 – ERO Enterprise senior leadership (ERO-Executive Management Group or "ERO-EMG") continues maturing the collaborative decision-making process and setting the direction

and policy for the enterprise as well as driving this collaboration throughout the ERO Enterprise organizations.

Action Item 7 – All nine ERO entities abide by the joint enterprise decisions of the ERO-EMG, and the NERC CEO should make final determinations if consensus is otherwise not achievable for an action that is required.

Action Item 8 – With NERC leading, the ERO Enterprise develops a core set of methods, practices, procedures, and tools to support unified implementation of the major statutory functions of NERC. In doing so, the ERO Enterprise commits to put the best talent available throughout the collective organizations to achieve this goal.

Action Item 9 - The ERO EMG develops ERO Enterprise IT Applications, where appropriate, to support common processes, to enhance the efficiency and effectiveness of Regional Entities' practices, to increase the consistency of the interface with registered entities, and to facilitate NERC's oversight function.

Action Item 10 – All parties of the ERO Enterprise, including leadership and staffs, convey shared and consistent messages from the enterprise perspective and communicate together to minimize messages emphasizing self-importance or uniqueness.

Action Item 11 – NERC and Regional Entities continue the joint board coordination to ensure oversight and accountability of all elements of the enterprise, and should continue to refine and expand coordinated outreach to government entities in the U.S. and Canada, stakeholders, and media.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RM15-11-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION REGARDING THE LOS ALAMOS NATIONAL LABORATORY TECHNICAL PAPER

The North American Electric Reliability Corporation ("NERC") hereby provides comments regarding the September 2015 technical paper prepared by the Los Alamos National Laboratory ("LANL") titled *Review of the GMD Benchmark Event in TPL-007-1* ("LANL Report"),[1] filed by the Foundation for Resilient Societies in the above-captioned docket on September 30, 2015.[2] NERC submits these comments as the Commission-certified electric reliability organization responsible for the development and enforcement of mandatory Reliability Standards,[3] including the proposed Reliability Standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance ("GMD") Events.

NERC welcomes the additional discussion brought about by the LANL Report and the opportunity to comment on the analysis and recommendations. NERC encourages rigorous review of all aspects of this important Reliability Standard and appreciates the U.S. Department

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[1] Los Alamos Nat'l Lab., *Review of the GMD Benchmark Event in TPL-007-1*, Report LA-UR-15-25609 (Sept. 2015).

[2] On October 2, 2015, the Federal Energy Regulatory Commission ("FERC" or the "Commission") issued a Notice Setting Comment Period, allowing interested parties 20 days to comment on the LANL Report as well as NERC's September 23, 2015 comments submitted in reply to certain other comments made in a prior public comment period.

[3] *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007), *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

of Energy and the LANL undertaking an independent review of the benchmark GMD event developed by NERC for use with proposed TPL-007-1 ("Benchmark GMD Event").

However, NERC maintains that the proposed Benchmark GMD Event provides a scientifically sound, technically justified approach for identifying GMD impacts with the potential to cause "instability, uncontrolled separation, or cascading failures of the Bulk-Power System" in accordance with Order No. 779.[4] Therefore, NERC reiterates its request that the Commission approve the proposed standard, without modification, as just, reasonable, not unduly discriminatory or preferential, and in the public interest, consistent with the Notice of Proposed Rulemaking.[5]

I. COMMENTS

The LANL Report provides the results of a review and analysis of the proposed Benchmark GMD Event; specifically: (i) the estimate of the 1-in-100 year geoelectric field magnitude; (ii) the scaling of the Benchmark GMD Event based on geomagnetic latitude; and (iii) the effect of earth conductivity data on scaling the Benchmark GMD Event. The LANL Report identifies several concerns and makes recommendations for certain aspects of the Benchmark GMD Event to be reanalyzed.

Following careful consideration of the LANL Report, NERC maintains that the proposed Benchmark GMD Event provides a reasonable and technically-supported scientific and engineering approach to evaluating the potential impacts of a severe GMD event on reliability. NERC provides its comments on specific aspects of the LANL Report below. NERC looks

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[4] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 (2013) at P 84 ("Order No. 779"), *reh'g denied*, 144 FERC ¶ 61,113 (2013).

[5] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 151 FERC ¶ 61,134 at P 22 (2015) ("NOPR") ("Pursuant to section 215(d) of the [Federal Power Act] FPA, the Commission proposes to approve Reliability Standard TPL-007-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.").

forward to working with the sponsor of the report, the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, to identify areas for further research and collaboration as part of its ongoing efforts to advance the understanding of the potential reliability impacts of severe GMD events.

A. The Reference Peak Geoelectric Field

1. LANL Report

The LANL Report analyzes the same International Monitor for Auroral Geomagnetic Effects ("IMAGE") magnetometer data set used in the development of the proposed Benchmark GMD Event; however, LANL states that its analysis of this data set has differed at each step from the analysis employed in the proposed Benchmark GMD Event in order to address certain statistical concerns that it has identified.[6] The LANL Report recommends that certain aspects of the proposed Benchmark GMD Event be reanalyzed according to LANL's recommended approach.

Among other things, the LANL Report recommends that the Benchmark GMD Event be "reanalyzed with consideration for the time correlations between IMAGE magnetometer samples (or other datasets) to develop a statistically meaningful definition of an independent GMD event."[7] As observed in the LANL Report, "[t]he physics of the electrojet during a GMD event creates time correlations in the resulting geo-magnetic and geo-electric fields."[8] The report states that such correlations could create biases in statistical analysis because data that are counted as

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6 These differences are summarized on page 6 of the LANL Report.

7 LANL Report at 7.

8 *Id.* at 4.

independent and discrete events are actually related to other events in the data set; as a result, these events may be over-counted and skew the analysis.[9]

Using its recommended, alternative approach, LANL calculates a 1-in-100 year peak geoelectric field value of 13.2 V/km (average), with a range of 8.4 V/km to 16.6 V/km, compared to the proposed Benchmark GMD Event value of 8 V/km.[10]

2. NERC Comments

NERC offers two observations of the analysis contained in the LANL Report. First, as NERC explained in its prior filings in this proceeding, the proposed Benchmark GMD Event was developed using a technically-justified approach that uses area magnetic field data to determine the 1-in-100 year peak geoelectric field.[11] An important distinction between the proposed Benchmark GMD Event and other estimates of a 1-in-100 year GMD event, including the estimate presented in the LANL Report, is the consideration given to regional scales appropriate for the Bulk-Power System.

The 1-in-100 year peak geoelectric field values in the LANL Report are calculated from individual station data, rather than area magnetic field data. Like other estimates of 1-in-100 year peak geoelectric fields for single geographic points, the results are higher than the proposed Benchmark GMD Event. However, and as discussed more fully in NERC's NOPR Comments, applying a single-point maximum geoelectric field over the entire area of a power system would

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9 *See id.*

10 *Id.* at 7.

11 *See, e.g.*, *Comments of the North American Electric Reliability Corporation in Response to Proposed Rulemaking*, Docket. No. RM15-11-000 (July 27, 2015) at 7-8 ("NERC's NOPR Comments"). For a description of the technical basis for this approach, *see* Antti Pulkkinen, Emanuel Bernabeu, Jan Eichner, Ari Viljanen, and Chigomezyo Ngwira, *Regional-Scale High-Latitude Extreme Geoelectric Fields pertaining to Geomagnetically Induced Currents*, EARTH, PLANETS AND SPACE 2015 67:93 (2015), *available at* http://www.earth-planets-space.com/content/67/1/93.

consistently overestimate geomagnetically induced currents ("GICs") above the levels expected from a 1-in-100 year GMD event.[12] As a result, GMD Vulnerability Assessments would be unduly pessimistic, representing conditions more extreme than a 1-in-100 year GMD event. NERC and industry, through the standards development process, determined that an appropriately defined 1-in-100 year GMD event was a conservative planning criterion that would address the risks from a GMD event on the order of the March 1989 event and reasonably protect against more extreme events.[13]

In contrast to the LANL estimated 1-in-100 year event, the proposed Benchmark GMD Event makes use of area magnetic field data to determine the 1-in-100 year peak geoelectric field magnitude. In doing so, GIC calculations derived from the Benchmark GMD Event would not be biased by observed, temporary, and localized peak geoelectric fields at individual geographic points. Instead, GMD Vulnerability Assessments based on the Benchmark GMD Event would realistically identify potential instability, uncontrolled separation, and cascading in the Bulk-Power System caused by a 1-in-100 year GMD event, consistent with the Commission's guidance in Order No. 779.

Second, the proposed Benchmark GMD Event addresses the concerns described in the LANL Report of statistical bias caused by time correlated data. The development of the proposed Benchmark GMD Event included extreme value analysis to determine the 95% confidence bound of the 1-in-100 year peak geoelectric field.[14] The extreme value analysis was performed

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12 *See* NERC's NOPR Comments at 7.

13 *See Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events,* Docket No. RM15-11-000 (Jan. 21, 2015) at 16 (the "Petition").

14 *See id.* at 17.

on a data set consisting of daily maximum geoelectric field amplitudes.[15] Because the maximums are daily values, the analysis is not biased by short time correlations as described in the LANL Report. Results of the extreme value analysis indicate that the proposed Benchmark GMD Event peak geoelectric field is above the 95% confidence bound for a 1-in-100 year event.[16]

B. Latitude Scaling Factor

1. LANL Report

The LANL Report also analyzed the proposed Benchmark GMD Event latitude scaling factor used to tailor the GMD Vulnerability Assessments to entity-specific locations. Observing that there is significant uncertainty in latitude scaling because there are no recorded storms the size of the Benchmark GMD Event, the report concluded that a physical model is needed to derive scaling factors from the available historical data. The LANL Report recommends adding a factor-of-two margin to the scaling factors used in the proposed standard for conservatism until such time as a model is developed.[17]

2. NERC Comments

The latitude scaling factor in proposed Reliability Standard TPL-007-1 accurately models the drop in geoelectric field that has been exhibited in analysis of major recorded geomagnetic storms.[18] While the events in this data set are not equivalent size to the Benchmark GMD Event, they capture the maximum observed shift in the latitude boundary of the auroral electric current

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15 Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 11.

16 *Id.* at 13. Derived from extreme value analysis, the upper limit of the 95% confidence interval for a 100-year return level is 5.77 V/km.

17 LANL Report at 12.

18 *See* NERC's NOPR Comments at 9.

systems that drive severe GMDs.[19] The scaling factors represent the maximum expansion of the auroral electric current systems observed for major storms since the late 1980s.

NERC is committed to advancing the understanding of the reliability risks posed by severe GMDs and will continue to pursue modeling enhancements for assessing GMD impacts. NERC supports the Commission's objectives for continued research[20] and agrees that future research should examine latitude scaling of geoelectric fields by assessing additional data and information. This effort could include development of models to further "extrapolate the small to moderate disturbance data currently in the historical record to disturbances as large as the TPL-007-1 Benchmark [GMD] Event," as suggested in the LANL Report.[21] However, while physical models may be able to provide additional insights in the future, the currently-available recorded data provides a strong technical basis for approval of the proposed TPL-007-1 Reliability Standard.

C. Earth Conductivity

1. LANL Report

The LANL Report observes that proposed Reliability Standard TPL-007-1 includes several possible approaches for adapting the Benchmark GMD Event to a local area using models for earth conductivity. Noting that "[m]ore work needs to be done to generate better-defined Earth layer conductivity data sources" for use in the proposed standard, the report

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19 *See* C. Ngwira and A. Pulkkinen et al., *Extended Study of Extreme Geoelectric Field Event Scenarios for Geomagnetically Induced Current Applications*, 11 SPACE WEATHER 121 (2013). Table 1 on page 2 describes the auroral expansion of the major recorded storms.

20 *See* NOPR at P 39.

21 *See* LANL Report at 12.

recommends that that the standard should use the worst-case earth conductivity configurations where specific detailed data is not known.[22]

2. NERC Comments

The proposed Benchmark GMD Event includes default scaling factors for earth conductivity based on publicly-available earth models.[23] Some of the earth models contain ranges of conductivity values in some layers, rather than distinct conductivity values, due to complexities in the Earth's composition. The earth conductivity scaling factors used in proposed TPL-007-1 are based on the analysis and "assigned value" that lies within these ranges based on the geophysical analysis described in a 2012 study by the Electric Power Research Institute.[24]

NERC agrees that more research into earth conductivity models is needed, and is working with research partners and industry to enhance these models in the future.[25] However, NERC maintains that the scaling factors contained in the proposed Benchmark GMD Event are derived from technically justified models resulting from peer-reviewed research and currently available information. This strong technical justification supports approval of the proposed TPL-007-1 Reliability Standard as written.

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22 *Id.* at 15-16.

23 *See* Petition at 19.

24 Electric Power Research Institute, *One-Dimensional Earth Resistivity Models for Selected Areas of Continental United States & Alaska*, Product ID 1026430 Technical Update (Dec. 2012), *available at* http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026430.

25 For a discussion of NERC's ongoing collaborative research efforts, *see* NERC's NOPR Comments at 13.

II. CONCLUSION

NERC respectfully requests that the Commission consider these comments and approve the proposed TPL-007-1 Reliability Standard as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

Respectfully submitted,

/s/ Lauren A. Perotti

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Counsel for the North American Electric Reliability Corporation

Date: October 22, 2015

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 22nd day of October, 2015.

/s/ Lauren A. Perotti

Lauren A. Perotti

Counsel for the North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

November 17, 2015

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Compliance Filing of the North American Electric Reliability Corporation Request for Approval of Amended Compliance and Certification Committee Charter, Docket No. RR15-11-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC")[1] submits this compliance filing in accordance with the Commission's August 21, 2015 Order in Docket No. RR15-11-000.[2] In its August 21 Order, the Federal Energy Regulatory Commission conditionally approved NERC's proposed revisions to the Compliance and Certification Committee Charter ("CCC Charter") and directed NERC to submit a compliance filing retaining language in the CCC Charter consistent with the definition of Hearing Panel in Appendix 4E of the NERC Rules of Procedure.[3] Appendix 4E states that voting members on a Hearing Panel must be "at arm's length from" parties to the hearing.

[1] The Federal Energy Regulatory Commission ("FERC" or "the Commission") certified NERC 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).
[2] *North American Electric Reliability Corporation*, 152 FERC ¶ 61,142 (2015) ("August 21 Order").
[3] The Commission's order directed NERC to submit a compliance filing with 60 days of the date of the order. On October 2, 2015, NERC filed a motion in the above-captioned docket for an extension of time until November 19, 2015 to file revisions to the CCC Charter. The extension requested was to allow the NERC Board of Trustees to approve the proposed revisions at its regularly scheduled meeting on November 5, 2015. Upon consideration, the Commission granted the extension on October 2, 2015.

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This compliance filing addresses the Commission's direction by reinstating the original language of the Hearing Panel provision of the CCC Charter regarding the requirement that voting members of the committee must be "at arm's length from parties to the hearing" to be nominated or volunteer for selection to the hearing panel.

This filing consists of this transmittal letter; Attachment 1, which contains a clean version of the revised CCC Charter; and Attachment 2, which contains a redlined version of the revised CCC Charter.

NERC respectfully requests that the Commission accept this compliance filing.

NERC thanks the Commission for its consideration of this filing. Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Teresina A. Stasko
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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 17th day of November 2015.

/s/ Sara Minges
Senior Compliance Enforcement Analyst
North American Electric Reliability Corporation

Attachment 1

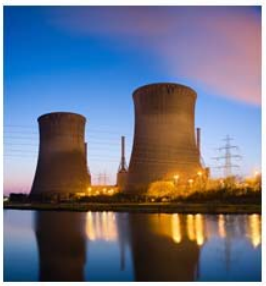
Clean version of the revised CCC Charter

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance and Certification Committee Charter

November 5, 2015

RELIABILITY | ACCOUNTABILITY



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Mission

In the capacity of a North American Electric Reliability Corporation (NERC) Board of Trustees (Board)-appointed stakeholder committee serving and reporting directly to the NERC Board, the Compliance and Certification Committee (CCC) will engage with, support, and advise the NERC Board and NERC regarding all facets of the NERC Compliance Monitoring and Enforcement Program (Compliance and Enforcement program), Organization Registration program (Registration program), and Organization Certification program (Certification program). As a committee providing support and advice but otherwise independent of the execution of these programs, the CCC will monitor NERC's adherence to the Rules of Procedure (ROP) for these programs. Also and in a similar manner, as a committee independent of the Reliability Standards development process, the CCC will be the body responsible for monitoring NERC's adherence to the (ROP) regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Standards process as defined in the appeals section of the Standard Processes Manual. The CCC is also responsible for establishing and implementing a program to monitor NERC's compliance with the Reliability Standards that apply to NERC.

Compliance and Certification Committee Functions

To fulfill its mission, the CCC performs the following functions:

1. Organizes and conducts committee meetings directly with NERC staff regarding all facets of the Compliance and Enforcement, Registration, and Certification programs;[1]
2. Provides comments and recommendations to the NERC Board and NERC staff;
3. Provides comments to NERC with respect to stakeholders' perception of the policies, practices, and effectiveness of the Compliance and Enforcement program, Registration program, and Certification program;
4. Recommends revisions of the electric reliability organization (ERO) ROP related to the Compliance and Enforcement program, Registration program, and Certification program to the NERC Board;
5. Establishes and implements programs to monitor:[2]
    a. NERC's adherence to Section 405 for Compliance Monitoring and Enforcement, including but not limited to the uniform CMEP (Appendix 4C) and the Sanction Guidelines (Appendix 4B).
    b. NERC's adherence to Section 506 for Organization Registration and Certification, including but not limited to the Organization Registration and Certification Manual (Appendix 5A).
    c. NERC's adherence to Section 300 of the ROP regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Reliability Standards process as defined in the appeals section of the Reliability Standards Development Procedure. Committee members who have participated in the development process for a particular Reliability Standard shall not participate in the committee's monitoring of that process.
    d. NERC's compliance with the Reliability Standards that apply to NERC.
6. Serves as the hearing body for any contest regarding findings of or penalties or sanctions for violation(s) of Reliability Standard(s) where NERC is directly monitoring the entity for compliance with those standards (registered entity by agreement with a Regional Entity or absent a delegation agreement; the Region itself where approved standards are applicable to the Region) as described in Section 408 of the NERC ROP;
7. As directed by the NERC Board, serves as the mediator for any disagreements between NERC and the Regional Entities concerning NERC performance audits of Regional Entities' compliance programs. When directed by the Board to serve as mediator, the committee chair will appoint three disinterested members of the committee to meet with representatives of NERC and the Regional Entity to attempt to resolve the matter.
8. Actively supports the Standards Committee in the development of new and revised standards by providing a pool of qualified compliance oriented personnel for participation in the compliance administration element phase of the standards development process;
9. Provides assistance to NERC and the Regional Entities to implement the Compliance and Enforcement, Registration, and Certification programs; and

[1] Meetings are conducted under Section 4 of this Charter.

[2] Monitoring by the CCC is ongoing and does not preclude, interfere with or replace, in whole or in part, the NERC Board's responsibility to conduct and provide such reviews of these programs as required by Federal Energy Regulatory Commission (the Commission) regulations, 18 C.F.R. § 39.3.c: "The Electric Reliability Organization shall submit an assessment of its performance three years from the date of certification by the Commission, and every five years thereafter."

10. Undertakes assignments from the Board or the Board's Compliance Committee related to compliance and enforcement, organization registration, organization certification, and standards development.

Membership

Goals

The CCC provides for balanced discussion, commentary, and recommendations on compliance issues by bringing together a wide diversity of opinions and perspectives from NERC member sector experts who have particular familiarity, knowledge, and experience in the area of compliance and NERC Standards and Regional Standards.

Appointment and Terms of Service

Members are appointed to the committee by the NERC Board and serve on the committee at the pleasure of the Board. Member terms are the lesser of three years from appointment or interim approval (Section 5.b), replacement, or removal by the Board. Members may be reappointed at the conclusion of a term. There is no limitation on the number of times a member may be reappointed. A member may be recommended to the Board for reappointment by the Nominating Subcommittee by self- nomination. To the extent practicable, member terms will be staggered such that approximately one-third of the committee is subject to reappointment or replacement each year.

Qualifications

Individuals deemed qualified to serve on the committee will generally include senior-level industry experts who have particular familiarity, knowledge, and experience in the area of compliance, compliance enforcement, compliance administration and management, organization responsibilities and registration, organization certification, and NERC Standards and Regional Standards. These individuals should be involved with internal compliance programs within their respective organizations.

Expectations

Committee members are expected to represent the interests of the sector they represent to the best of their ability and judgment. In addition to the duties, rights, and privileges described elsewhere in this charter, committee members will:

1. Act consistently during meetings with the procedures in this manual and Robert's Rules of Order;
2. Demonstrate and provide knowledge and expertise in support of committee activities;
3. Adjudicate in a fair and unbiased manner that meets applicable legal and due process requirements when participating in hearing procedures conducted under the NERC ROP Section 408;
4. Solicit comments and opinions from constituents and groups of constituents or trade organizations represented by the member and convey them to the committee;
5. Respond promptly to all committee requests, including requests for reviews, comments, and votes on issues before the committee;
6. Arrange for a proxy to attend and vote at committee meetings in the member's absence; and
7. Respond promptly to all requests to register for committee meetings.

Representation

The membership structure of the CCC will be modeled upon the membership structure of the NERC Member Representatives Committee (MRC) as described in NERC's Bylaws (the Bylaws) Article VIII Section 2 [see Attachment A]. This should produce a committee that has an appropriate balance of entities subject to compliance with the NERC Reliability Standards and NERC's Compliance and Enforcement program, and others affected by the Standards and the Compliance and Enforcement program.

Regional Entities

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate one member to the committee. In aggregate, the sector will have voting strength equivalent to two members. The voting weight of each Regional member's vote will be set such that the sum of the weight of all available Regional members' votes is two votes.

Canadian Representation

The committee structure will include representation by Canadians as laid out in Article VIII Section 4 of the Bylaws.

NERC Membership

Users, owners, and operators of the bulk power system are subject to the Compliance, Registration, and Certification programs regardless of whether they are NERC members. It is expected that committee members will generally be from organizations who are NERC members; however, committee members may be non-members of NERC who are subject to the qualifications identified herein and meeting requirements laid out in the Bylaws for non-NERC-member participation in the MRC.

Selection

The CCC will conduct open nominations processes to receive nominations to fill any membership vacancies. Prospective members of the committee may be identified to the CCC via any means the committee finds acceptable, including solicited or unsolicited nomination by a recognized industry group or association, general open solicitation by the committee for nomination(s), individuals' self-nomination, directed solicitation by the committee to an individual or individuals, or referral by the Board or other NERC body or committee.

Nominating Subcommittee

The CCC will annually appoint a Nominating Subcommittee to identify, qualify, and recommend individuals to fill sector representative vacancies on the committee or, when required, to serve as the chair or vice chair of the committee. The subcommittee will identify the individuals they are recommending to the full CCC for review. Individuals recommended by the subcommittee for appointment to the committee must be approved by the Board.

Interim Approval

Upon approval of the committee, individuals identified and selected by the Nominating Subcommittee for membership on the committee may serve as members on an interim basis pending their appointment by the Board.

Expertise

When selecting individuals to recommend for committee membership, the Nominating Subcommittee will seek to engage individuals who, in aggregate, provide the committee with a level and breadth of expertise sufficient to achieve its goals and fulfill its scope and responsibilities while respecting other important factors such as industry sector, Region, interconnection, and country.

Regional Entity Members

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate an individual to serve as a member representing their organization. The Nominating Subcommittee will defer to these nominations. The nomination is non-binding upon the Board. Vacancies on the committee will exist where the Regional Reliability Organization or Regional Entity has not provided a nomination.

Canadian Members

The Nominating Subcommittee will endeavor to attract and engage Canadians with suitable qualifications and expertise in adequate numbers to satisfy Article VIII Section 4 of the Bylaws. Recognized Canadian organizations

such as the Canadian Electricity Association and Canada's Energy and Utility Regulators will be consulted and solicited for assistance in recruiting Canadians to serve on the committee. All members considered to be serving as Canadians on the committee will be expected to have an endorsement, as appropriate, of such an organization. Canadian representatives should be capable of representing Canadian viewpoints in committee activities, in addition to the sector that they otherwise represent. Consistent with practice regarding the MRC, the Board may appoint additional Canadian individuals to the committee towards satisfying Article VIII Section 4 of the Bylaws.

Industry Sector Members

The Nominating Subcommittee will assess the qualifications of nominees and select individuals to recommend to the NERC Board for appointment to the committee. The subcommittee may give preference to candidates nominated by organizations generally considered by the industry as representative of a broad cross-section of the industry sector in question, such as an industry trade association. A NERC Member sector may elect to identify sector representatives for nomination to the Nominating Subcommittee through a process approved by the NERC Board.

General Nominations and Appointment Process

The committee's secretary administers the general nominations process.

Requesting Nominations

The NERC staff will request nominations and will forward all nominations received to the Nominating Subcommittee. The Nominating Subcommittee will then prepare its recommended slate of members. The recommended slate will be reviewed by the whole committee for information purposes before it is submitted to the Board. The committee may approve the slate to serve as members on an interim basis, pending appointment by the Board at the Board's earliest convenience, but will not otherwise act on the slate.

Board Approval

The Nominating Subcommittee will present the recommended committee membership slate to the Board for approval. If the Board approves the recommended committee slate, each member on the slate is appointed. The Board may also appoint members individually as needed to meet membership balance and fill vacancies.

Vacancies and Non-participation

The committee's secretary will administer the nominations process for vacancies on the committee.

Addressed on an Ongoing Basis

Vacancies on the committee can be addressed on an ongoing basis through receipt and consideration of both solicited and unsolicited nominations for the vacant positions.

Role of the Nominating Subcommittee

Nominations received for vacancies will be vetted by the Nominating Subcommittee in the same manner as general nominations. The subcommittee may subsequently and individually recommend nominees they deem qualified to the NERC Board for consideration for appointment to the committee. Existing committee members may also approve such individuals to serve as members on an interim basis pending full appointment by the Board.

Resignations

By the Member

In the event a member can no longer serve on the committee, that member will submit a written resignation to the committee chair or the secretary.

Requested by the Chair

The chair may request any committee member who ceases to participate in the committee, as indicated by not attending or sending a proxy for two consecutive meetings, to submit a resignation or to request continuation of membership with an explanation of extenuating circumstances. If a written response is not received within 30 days of the chair's request, the lack of response will be considered a resignation.

Referral to the Nominating Subcommittee

The committee chair will refer the vacancy resulting from a resignation to the Nominating Subcommittee of the committee. If a recent list of nominations is available to the Nominating Subcommittee that it deems to be valid, the subcommittee will recommend a replacement nominee; otherwise, the subcommittee will request NERC staff prepare a new solicitation for nominations to fill that position. The Nominating Subcommittee will follow the previously stated criteria in recommending a replacement.

By the Board

Committee members serve at the pleasure of the Board who may request resignation from, remove, or replace a member from the committee, as the Board deems appropriate.

Interim Approval

The committee chair may seek a vote of the committee to allow the proposed replacement member to be seated, pending appointment of the replacement at the Board's next scheduled meeting.

Proxies

A substitute representative, or proxy, may attend and vote during all or a portion of a committee meeting in lieu of a voting member provided the absent member notifies the committee chair, vice chair, or secretary of the proxy.

Notification

Such notification will be in writing (electronic medium is acceptable). The proxy representatives and their affiliation will be named in the correspondence.

Serving as Proxy

A voting member of a committee may not serve as a proxy for another voting member on the same committee (i.e. a member may not cast more than their own vote).

Exclusions

Regional Entity Staff

Regional Entity staff members who administer any portion of the Compliance and Enforcement program, Registration program, or Certification program for that Regional Entity, or for any other Regional Entity, may not serve as a member of the CCC.

Organizations

No two individuals from the same organization, or affiliated organizations, may serve concurrently on the committee. Any committee member who has a membership conflict of this nature is obligated to notify the committee secretary, who shall inform the committee chair. Members impacted by such a conflict, such as through a merger of organizations, may confer between themselves to determine which member should resign from the committee and notify the committee secretary and chair; however, if both members are within the same industry sector and cannot reach an amicable solution by determining the member to remain, the Nominating Subcommittee will review the qualifications of each member and propose the member to remain to the full committee who will determine which member shall continue to serve, subject to Board approval. If the conflict is not resolved in a timely manner by the impacted members, the committee chair shall notify all members of the

affected industry sectors recommending actions to resolve the conflict. If the membership conflict is still unresolved, the committee chair shall take the conflict to the NERC Board for resolution.

NERC Staff

The Director of Compliance Assurance shall not be a member of the committee or vote on committee business. The Director of Compliance Assurance and the secretary shall be recused from participating in any committee activity that involves monitoring of NERC's adherence to ROP or activity that the Director of Compliance Assurance oversees. If the NERC staff coordinator has been recused from participating in a Committee activity, the chair shall appoint another member of the committee as acting secretary for any meetings or other activities from which the NERC staff coordinator is recused.

Changes in Member Affiliation

A committee member whose affiliation has changed may retain the membership position under these circumstances:

1. The new organization is in the same industry sector, and
2. The member meets all other membership requirements.

Conflict of Interest

No committee member may have a conflict of interest that would impair his or her ability to fulfill obligations under this charter. Any committee member who knows of any form of membership conflict, such as working for an entity affiliated with that of another committee member, will notify the committee chair within 10 business days of obtaining that knowledge.

Meetings

In the absence of specific provisions in this manual, all committee meetings will follow Roberts Rules of Order.

Quorum

Two-thirds Requirement

The quorum necessary for transacting business at meetings of the committee is two-thirds of the voting members currently on the committee's roster.

Interim Basis

Voting members approved by the committee on an interim basis, pending appointment by the Board, will be counted in the determination of a quorum.

Lack of Quorum

If a quorum is not present at the beginning of the meeting, the committee may not take any actions requiring a vote by the committee; however, the chair may, with the consent of the members present, elect to allow discussion of the agenda items.

Voting

Actions by members of the committee will be approved upon receipt of the affirmative vote of two-thirds of the votes present (including proportional votes by Regional Representatives) at any meeting at which a quorum is present.

Antitrust Guidelines

All persons attending or otherwise participating in a NERC committee meeting will act in accordance with NERC's Antitrust Compliance Guidelines at all times during the meeting.

Open Meetings

NERC committee meetings will be open to the public, except as noted below under Confidential Information.

Confidential Sessions

At the discretion of the CCC chair, a meeting or portion of a meeting may have attendance limited based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive information or confidential information to one or more parties. All hearings of compliance matters will be confidential sessions. Confidential information will only be disclosed as provided by NERC ROP 1500. Confidentiality agreements may also be applied, as necessary, to protect sensitive information or confidential information.

Types of Meetings

Meetings may be conducted in person, by conference call, or by other means. The procedures contained in this manual will apply to all meetings regardless of how they are conducted.

Majority and Minority Views

All members of a committee will be given the opportunity to provide alternative views on an issue. The results of committee actions, including recorded minutes, will reflect the majority as well as any minority views of the committee members. The chair will communicate both the majority and any minority views in presenting results to the Board.

Action Without a Meeting

Two-thirds Majority

Any action required or permitted at a meeting of the committee may be taken without a meeting if two-thirds of the total votes available to the members of the CCC (including the proportional votes available to Regional Representatives) approve taking the action outside of a meeting.

Procedure

Such action without a meeting will be performed by mail or electronic ballot (e.g., telephone, fax, email, or Internet) and will be recorded in the minutes as a roll call ballot. The secretary will announce the action required at least 10 days before the date on which the action is to be voted. As time permits, members should be allowed a window of 10 business days to vote. The secretary will provide the results of such an action within 10 business days of the close of the voting period.

Officers and Staff

General

Number of Positions

The committee will have two officers and one secretary.

Officers

The committee officers will be one chair and one vice chair.

Executive

The committee shall retain an Executive Committee consisting of the committee officers, subcommittee chairs, secretary, and the Director of Compliance Assurance.

Secretary

The NERC staff coordinator will serve as the committee's secretary.

Voting of Officers

The committee chair and vice chair are voting members of the committee.

Officers Nominated by the Nominating Subcommittee

The CCC Nominating Subcommittee will recommend a chair and a vice chair who are then appointed by the NERC Board for a two-year term. The term of the chair and the vice chair, except for the first year, will begin on July 1 and end on June 30.

Officers as Sector Representatives

The chair and vice chair are selected from the membership of the committee and, in addition to their chair or vice chair responsibilities, will continue to serve as a member for the sector for which they were appointed to the committee.

Chair

The chair will direct and provide general supervision of committee activities, including the following:

1. Coordinate the schedule of all committee meetings, including approval of meeting duration and location;
2. Develop committee agendas and rule on any deviation, addition, or deletion from a published agenda;
3. Preside at and manage committee meetings, including the nature and length of discussion, recognition of speakers and proxies, motions, and voting;
4. Will lead or direct the conduct of any hearings and the preparation of any adjudicatory documents by the committee under Section 408 of the NERC ROP;
5. Will ensure actions and undertakings by the committee under the NERC ROP Section 408 meet all applicable legal and due process requirements;
6. Will act as spokesperson for the committee at forums inside and outside of NERC; and
7. May attend meetings of the NERC Board when necessary to report to the Board on committee activities.

Vice Chair

The vice chair will assume the responsibilities of the chair under the following conditions:

1. At the discretion of the chair (for brief periods of time);

2. When the chair is absent or temporarily unable to perform the chair's duties; or
3. When the chair is permanently unavailable or unable to perform the chair's duties. In the case of a permanent change, the vice chair will continue to serve until a new chair is nominated and selected by the Board.

Staff Coordinator

A member of the NERC staff will be selected by NERC's Director of Compliance Assurance to serve as the staff coordinator and secretary of the committee. The staff coordinator is not a committee member and does not have a vote. Under the direction of the committee executive and applicable NERC bylaws, guidelines, and ROP, the staff coordinator will do the following:

1. Manage the day-to-day operation and business of the committee;
2. Prepare and distribute the notices of the committee meetings, prepare the meeting agenda, and prepare and distribute the minutes of the committee meetings; and
3. Act as the committee's parliamentarian.

Nominating Subcommittee

Appointment

The CCC will annually appoint a Nominating Subcommittee.

Five Members

The subcommittee will consist of five members nominated by the committee chair and approved by the committee. The chair of the subcommittee will be selected by the CCC chair from among the five subcommittee members.

Appointed Annually

The chair will appoint the subcommittee members at the first regular meeting of the committee of the calendar year.

Length of term

The subcommittee members will serve for up to 14 months or until a new Nominating Subcommittee is authorized, whichever is earlier.

Duties

In addition to the duties, rights, and privileges described elsewhere in this manual, members of the Nominating Subcommittee will:

1. Prepare a slate of committee officer candidates for submission to the NERC Board for approval, and
2. Prepare a slate of recommended individuals to fill designated committee vacancies as required.

Subordinate Groups

Committee Organization

The CCC organizational structure will be arranged as allowed in the NERC Bylaws to support a superior-subordinate hierarchy that is ordered as follows: a committee, a subcommittee, a working group, and a task force, with a committee being primary and a task force being quaternary.

Subgroups

The committee may establish subcommittees, working groups, and task forces as necessary. The committee chair may also form any of these subordinate groups on behalf of the committee. The committee will be the responsible sponsor of all subordinate subcommittees, working groups, or task forces it may create, or that its subordinate subcommittees and working groups may create. The committee will keep the Board informed of all groups subordinate to the committee.

Subcommittees

The committee may establish subcommittees to which the committee may delegate some of the committee's broadly defined continuing functions. The committee will approve the scope of each subcommittee it forms. The committee chair will appoint the subcommittee officers (typically a chair and a vice chair) for a specific term (generally two years). The subcommittee officers may be reappointed for up to two additional terms. The subcommittee will work within its assigned scope and be accountable for the responsibilities assigned to it by the committee. The formation of a subcommittee, due to the permanency of the subcommittee, will be approved by the Board.

Working Groups

The committee or any of its subcommittees may delegate specific continuing functions to a working group. The sponsoring committee or subcommittee will approve the scope of each working group it forms. The chair of the sponsoring committee or subcommittee will appoint the working group officers (typically a chair and a vice chair) for a specific term (generally two years). The working group officers may be reappointed for up to two additional terms. The sponsoring committee or subcommittee will conduct a "sunset" review of each working group every two years. The working group will be accountable for the responsibilities assigned to it by the committee or subcommittee and will, at all times, work within its assigned scope.

Task Forces

The committee, subcommittee, or working group may assign specific work of a finite duration to a task force. The sponsoring committee, subcommittee, or working group will approve the scope of each task force it forms. The chair of the sponsoring committee, subcommittee, or working group will appoint the task force officers (typically a chair and a vice chair). Each task force will have a finite duration, normally less than one year. The sponsoring group will review the task force scope at the end of the expected duration and at each subsequent meeting of the sponsoring group after that until the task force is retired. Action of the task force sponsoring group is required to continue the task force past its defined duration. The sponsoring group should consider promoting to a working group any task force that is required to work longer than one year.

Membership and Representation

The membership of each subcommittee, working group, and task force should be established to address the need for expertise and balance of interests. Each group's membership requirements will be defined within the group's approved scope.

As a general guide, the broader the group's scope, the more emphasis there should be on balancing of interests. Therefore, subcommittees would be expected to have the broadest representation of appropriate industry

sectors, while a task force may be more focused on simply having the necessary expertise, and a working group may be somewhere between.

Each member of a subordinate group, and its officers, will be appointed by the chair of the sponsoring committee or group.

To the extent subgroup membership is of a representative nature, recommendations for staffing of the group should be provided in a manner consistent with the principles outlined in the staffing of a committee, including the use of an open nominations process. Regional Entity representatives should be recommended by the Regional Entity and Canadian representatives by the Canadian Electricity Association.

Preference may also be given to representatives recommended by broadly-based industry associations.

To the extent that subgroup membership is based on providing requisite expertise, the chair of the sponsoring committee or group may appoint members based on the relevant technical qualifications.

Procedures

Subcommittees, working groups, and taskforces will conduct business in a manner consistent with all applicable sections of this manual and Robert's Rules of Order.

Hearings

General

The CCC will conduct hearings, as necessary, to fulfill its function of serving as the hearing body for any contest between NERC and a Regional Entity regarding NERC findings, penalties, or sanctions for violation(s) of Reliability Standard(s) by the Regional Entity as described in Section 408 of the NERC ROP.

Hearing Procedure

Unless specifically identified otherwise elsewhere in this charter, the CCC's hearing procedure shall follow the hearing procedure mandated and approved by jurisdictional authorities for use by NERC and the Regional Entities in the Compliance and Enforcement program.

Hearing Panel

The committee shall not have a standing hearing panel. When a hearing is to be conducted, the CCC shall select five members to serve as the adjudicatory panel for that hearing. Members to serve on the panel shall be selected by vote of a valid quorum of the committee. Voting members of the committee at arm's length from parties to the hearing may be nominated or volunteer to stand for selection to the hearing panel. One or more alternates may also be selected, as the committee deems appropriate for the circumstances. A member may serve on more than one panel concurrently. A panel is disbanded upon conclusion of the hearing proceedings for which it was formed.

Attachment A

CCC Membership Structure

Primary Sector	Sub-Sector	Number of Members	Full Voting	Proportional Voting	Non-Voting
Investor-Owned Utility		2	X		
State/Municipal Utility		2	X		
Cooperative Utility		2	X		
Federal or Provincial Utility/Federal Power Marketing Administration		2	X		
Transmission Dependent Utility		2	X		
Merchant Electricity Generator		2	X		
Electricity Marketer		2	X		
Large End-use Electricity Customer		2	X		
Small End-use Electricity Customer		2	X		
Independent System Operator/Regional Transmission Organization		2	X		
Regional Entity	FRCC	1		X	
	RFC	1		X	
	ERCOT	1		X	
	MRO	1		X	
	NPCC	1		X	
	SERC	1		X	
	SPP	1		X	
	WECC	1		X	
Government	U.S. State	2	X		
	U.S. Federal	2			X
	Canadian Provincial	1			X
	Canadian Federal	1			X
Total		**34**			

Attachment 2

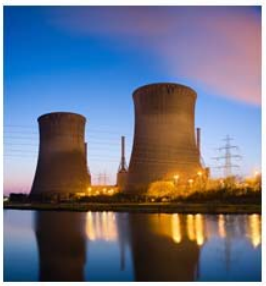
Redlined version of the revised CCC Charter

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance and Certification Committee Charter

November 5, 2015

RELIABILITY | ACCOUNTABILITY



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Mission

In the capacity of a North American Electric Reliability Corporation (NERC) Board of Trustees (Board)-appointed stakeholder committee serving and reporting directly to the NERC Board, the Compliance and Certification Committee (CCC) will engage with, support, and advise the NERC Board and NERC regarding all facets of the NERC Compliance Monitoring and Enforcement Program (Compliance and Enforcement program), Organization Registration program (Registration program), and Organization Certification program (Certification program). As a committee providing support and advice but otherwise independent of the execution of these programs, the CCC will monitor NERC's adherence to the Rules of Procedure (ROP) for these programs. Also and in a similar manner, as a committee independent of the Reliability Standards development process, the CCC will be the body responsible for monitoring NERC's adherence to the (ROP) regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Standards process as defined in the appeals section of the Standard Processes Manual. The CCC is also responsible for establishing and implementing a program to monitor NERC's compliance with the Reliability Standards that apply to NERC.

Compliance and Certification Committee Functions

To fulfill its mission, the CCC performs the following functions:

1. Organizes and conducts committee meetings directly with NERC staff regarding all facets of the Compliance and Enforcement, Registration, and Certification programs;[1]
2. Provides comments and recommendations to the NERC Board and NERC staff;
3. Provides comments to NERC with respect to stakeholders' perception of the policies, practices, and effectiveness of the Compliance and Enforcement program, Registration program, and Certification program;
4. Recommends revisions of the electric reliability organization (ERO) ROP related to the Compliance and Enforcement program, Registration program, and Certification program to the NERC Board;
5. Establishes and implements programs to monitor:[2]
    a. NERC's adherence to Section 405 for Compliance Monitoring and Enforcement, including but not limited to the uniform CMEP (Appendix 4C) and the Sanction Guidelines (Appendix 4B).
    b. NERC's adherence to Section 506 for Organization Registration and Certification, including but not limited to the Organization Registration and Certification Manual (Appendix 5A).
    c. NERC's adherence to Section 300 of the ROP regarding the Reliability Standards development process with the exception of appeals of substantive or procedural action or inaction associated with a Reliability Standard or the Reliability Standards process as defined in the appeals section of the Reliability Standards Development Procedure. Committee members who have participated in the development process for a particular Reliability Standard shall not participate in the committee's monitoring of that process.
    d. NERC's compliance with the Reliability Standards that apply to NERC.
6. Serves as the hearing body for any contest regarding findings of or penalties or sanctions for violation(s) of Reliability Standard(s) where NERC is directly monitoring the entity for compliance with those standards (registered entity by agreement with a Regional Entity or absent a delegation agreement; the Region itself where approved standards are applicable to the Region) as described in Section 408 of the NERC ROP;
7. As directed by the NERC Board, serves as the mediator for any disagreements between NERC and the Regional Entities concerning NERC performance audits of Regional Entities' compliance programs. When directed by the Board to serve as mediator, the committee chair will appoint three disinterested members of the committee to meet with representatives of NERC and the Regional Entity to attempt to resolve the matter.
8. Actively supports the Standards Committee in the development of new and revised standards by providing a pool of qualified compliance oriented personnel for participation in the compliance administration element phase of the standards development process;
9. Provides assistance to NERC and the Regional Entities to implement the Compliance and Enforcement, Registration, and Certification programs; and

[1] Meetings are conducted under Section 4 of this Charter.

[2] Monitoring by the CCC is ongoing and does not preclude, interfere with or replace, in whole or in part, the NERC Board's responsibility to conduct and provide such reviews of these programs as required by Federal Energy Regulatory Commission (the Commission) regulations, 18 C.F.R. § 39.3.c: "The Electric Reliability Organization shall submit an assessment of its performance three years from the date of certification by the Commission, and every five years thereafter."

10. Undertakes assignments from the Board or the Board's Compliance Committee related to compliance and enforcement, organization registration, organization certification, and standards development.

Membership

Goals

The CCC provides for balanced discussion, commentary, and recommendations on compliance issues by bringing together a wide diversity of opinions and perspectives from NERC member sector experts who have particular familiarity, knowledge, and experience in the area of compliance and NERC Standards and Regional Standards.

Appointment and Terms of Service

Members are appointed to the committee by the NERC Board and serve on the committee at the pleasure of the Board. Member terms are the lesser of three years from appointment or interim approval (Section 5.b), replacement, or removal by the Board. Members may be reappointed at the conclusion of a term. There is no limitation on the number of times a member may be reappointed. A member may be recommended to the Board for reappointment by the Nominating Subcommittee by self- nomination. To the extent practicable, member terms will be staggered such that approximately one-third of the committee is subject to reappointment or replacement each year.

Qualifications

Individuals deemed qualified to serve on the committee will generally include senior-level industry experts who have particular familiarity, knowledge, and experience in the area of compliance, compliance enforcement, compliance administration and management, organization responsibilities and registration, organization certification, and NERC Standards and Regional Standards. These individuals should be involved with internal compliance programs within their respective organizations.

Expectations

Committee members are expected to represent the interests of the sector they represent to the best of their ability and judgment. In addition to the duties, rights, and privileges described elsewhere in this charter, committee members will:

1. Act consistently during meetings with the procedures in this manual and Robert's Rules of Order;
2. Demonstrate and provide knowledge and expertise in support of committee activities;
3. Adjudicate in a fair and unbiased manner that meets applicable legal and due process requirements when participating in hearing procedures conducted under the NERC ROP Section 408;
4. Solicit comments and opinions from constituents and groups of constituents or trade organizations represented by the member and convey them to the committee;
5. Respond promptly to all committee requests, including requests for reviews, comments, and votes on issues before the committee;
6. Arrange for a proxy to attend and vote at committee meetings in the member's absence; and
7. Respond promptly to all requests to register for committee meetings.

Representation

The membership structure of the CCC will be modeled upon the membership structure of the NERC Member Representatives Committee (MRC) as described in NERC's Bylaws (the Bylaws) Article VIII Section 2 [see Attachment A]. This should produce a committee that has an appropriate balance of entities subject to compliance with the NERC Reliability Standards and NERC's Compliance and Enforcement program, and others affected by the Standards and the Compliance and Enforcement program.

Regional Entities

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate one member to the committee. In aggregate, the sector will have voting strength equivalent to two members. The voting weight of each Regional member's vote will be set such that the sum of the weight of all available Regional members' votes is two votes.

Canadian Representation

The committee structure will include representation by Canadians as laid out in Article VIII Section 4 of the Bylaws.

NERC Membership

Users, owners, and operators of the bulk power system are subject to the Compliance, Registration, and Certification programs regardless of whether they are NERC members. It is expected that committee members will generally be from organizations who are NERC members; however, committee members may be non-members of NERC who are subject to the qualifications identified herein and meeting requirements laid out in the Bylaws for non-NERC-member participation in the MRC.

Selection

The CCC will conduct open nominations processes to receive nominations to fill any membership vacancies. Prospective members of the committee may be identified to the CCC via any means the committee finds acceptable, including solicited or unsolicited nomination by a recognized industry group or association, general open solicitation by the committee for nomination(s), individuals' self-nomination, directed solicitation by the committee to an individual or individuals, or referral by the Board or other NERC body or committee.

Nominating Subcommittee

The CCC will annually appoint a Nominating Subcommittee to identify, qualify, and recommend individuals to fill sector representative vacancies on the committee or, when required, to serve as the chair or vice chair of the committee. The subcommittee will identify the individuals they are recommending to the full CCC for review. Individuals recommended by the subcommittee for appointment to the committee must be approved by the Board.

Interim Approval

Upon approval of the committee, individuals identified and selected by the Nominating Subcommittee for membership on the committee may serve as members on an interim basis pending their appointment by the Board.

Expertise

When selecting individuals to recommend for committee membership, the Nominating Subcommittee will seek to engage individuals who, in aggregate, provide the committee with a level and breadth of expertise sufficient to achieve its goals and fulfill its scope and responsibilities while respecting other important factors such as industry sector, Region, interconnection, and country.

Regional Entity Members

Each Regional Entity, or the applicable regional organization if no Regional Entity exists for the geographic area, may nominate an individual to serve as a member representing their organization. The Nominating Subcommittee will defer to these nominations. The nomination is non-binding upon the Board. Vacancies on the committee will exist where the Regional Reliability Organization or Regional Entity has not provided a nomination.

Canadian Members

The Nominating Subcommittee will endeavor to attract and engage Canadians with suitable qualifications and expertise in adequate numbers to satisfy Article VIII Section 4 of the Bylaws. Recognized Canadian organizations

such as the Canadian Electricity Association and Canada's Energy and Utility Regulators will be consulted and solicited for assistance in recruiting Canadians to serve on the committee. All members considered to be serving as Canadians on the committee will be expected to have an endorsement, as appropriate, of such an organization. Canadian representatives should be capable of representing Canadian viewpoints in committee activities, in addition to the sector that they otherwise represent. Consistent with practice regarding the MRC, the Board may appoint additional Canadian individuals to the committee towards satisfying Article VIII Section 4 of the Bylaws.

Industry Sector Members

The Nominating Subcommittee will assess the qualifications of nominees and select individuals to recommend to the NERC Board for appointment to the committee. The subcommittee may give preference to candidates nominated by organizations generally considered by the industry as representative of a broad cross-section of the industry sector in question, such as an industry trade association. A NERC Member sector may elect to identify sector representatives for nomination to the Nominating Subcommittee through a process approved by the NERC Board.

General Nominations and Appointment Process

The committee's secretary administers the general nominations process.

Requesting Nominations

The NERC staff will request nominations and will forward all nominations received to the Nominating Subcommittee. The Nominating Subcommittee will then prepare its recommended slate of members. The recommended slate will be reviewed by the whole committee for information purposes before it is submitted to the Board. The committee may approve the slate to serve as members on an interim basis, pending appointment by the Board at the Board's earliest convenience, but will not otherwise act on the slate.

Board Approval

The Nominating Subcommittee will present the recommended committee membership slate to the Board for approval. If the Board approves the recommended committee slate, each member on the slate is appointed. The Board may also appoint members individually as needed to meet membership balance and fill vacancies.

Vacancies and Non-participation

The committee's secretary will administer the nominations process for vacancies on the committee.

Addressed on an Ongoing Basis

Vacancies on the committee can be addressed on an ongoing basis through receipt and consideration of both solicited and unsolicited nominations for the vacant positions.

Role of the Nominating Subcommittee

Nominations received for vacancies will be vetted by the Nominating Subcommittee in the same manner as general nominations. The subcommittee may subsequently and individually recommend nominees they deem qualified to the NERC Board for consideration for appointment to the committee. Existing committee members may also approve such individuals to serve as members on an interim basis pending full appointment by the Board.

Resignations

By the Member

In the event a member can no longer serve on the committee, that member will submit a written resignation to the committee chair or the secretary.

Requested by the Chair

The chair may request any committee member who ceases to participate in the committee, as indicated by not attending or sending a proxy for two consecutive meetings, to submit a resignation or to request continuation of membership with an explanation of extenuating circumstances. If a written response is not received within 30 days of the chair's request, the lack of response will be considered a resignation.

Referral to the Nominating Subcommittee

The committee chair will refer the vacancy resulting from a resignation to the Nominating Subcommittee of the committee. If a recent list of nominations is available to the Nominating Subcommittee that it deems to be valid, the subcommittee will recommend a replacement nominee; otherwise, the subcommittee will request NERC staff prepare a new solicitation for nominations to fill that position. The Nominating Subcommittee will follow the previously stated criteria in recommending a replacement.

By the Board

Committee members serve at the pleasure of the Board who may request resignation from, remove, or replace a member from the committee, as the Board deems appropriate.

Interim Approval

The committee chair may seek a vote of the committee to allow the proposed replacement member to be seated, pending appointment of the replacement at the Board's next scheduled meeting.

Proxies

A substitute representative, or proxy, may attend and vote during all or a portion of a committee meeting in lieu of a voting member provided the absent member notifies the committee chair, vice chair, or secretary of the proxy.

Notification

Such notification will be in writing (electronic medium is acceptable). The proxy representatives and their affiliation will be named in the correspondence.

Serving as Proxy

A voting member of a committee may not serve as a proxy for another voting member on the same committee (i.e. a member may not cast more than their own vote).

Exclusions

Regional Entity Staff

Regional Entity staff members who administer any portion of the Compliance and Enforcement program, Registration program, or Certification program for that Regional Entity, or for any other Regional Entity, may not serve as a member of the CCC.

Organizations

No two individuals from the same organization, or affiliated organizations, may serve concurrently on the committee. Any committee member who has a membership conflict of this nature is obligated to notify the committee secretary, who shall inform the committee chair. Members impacted by such a conflict, such as through a merger of organizations, may confer between themselves to determine which member should resign from the committee and notify the committee secretary and chair; however, if both members are within the same industry sector and cannot reach an amicable solution by determining the member to remain, the Nominating Subcommittee will review the qualifications of each member and propose the member to remain to the full committee who will determine which member shall continue to serve, subject to Board approval. If the conflict is not resolved in a timely manner by the impacted members, the committee chair shall notify all members of the

affected industry sectors recommending actions to resolve the conflict. If the membership conflict is still unresolved, the committee chair shall take the conflict to the NERC Board for resolution.

NERC Staff

The Director of Compliance Assurance shall not be a member of the committee or vote on committee business. The Director of Compliance Assurance and the secretary shall be recused from participating in any committee activity that involves monitoring of NERC's adherence to ROP or activity that the Director of Compliance Assurance oversees. If the NERC staff coordinator has been recused from participating in a Committee activity, the chair shall appoint another member of the committee as acting secretary for any meetings or other activities from which the NERC staff coordinator is recused.

Changes in Member Affiliation

A committee member whose affiliation has changed may retain the membership position under these circumstances:

1. The new organization is in the same industry sector, and
2. The member meets all other membership requirements.

Conflict of Interest

No committee member may have a conflict of interest that would impair his or her ability to fulfill obligations under this charter. Any committee member who knows of any form of membership conflict, such as working for an entity affiliated with that of another committee member, will notify the committee chair within 10 business days of obtaining that knowledge.

Meetings

In the absence of specific provisions in this manual, all committee meetings will follow Roberts Rules of Order.

Quorum

Two-thirds Requirement

The quorum necessary for transacting business at meetings of the committee is two-thirds of the voting members currently on the committee's roster.

Interim Basis

Voting members approved by the committee on an interim basis, pending appointment by the Board, will be counted in the determination of a quorum.

Lack of Quorum

If a quorum is not present at the beginning of the meeting, the committee may not take any actions requiring a vote by the committee; however, the chair may, with the consent of the members present, elect to allow discussion of the agenda items.

Voting

Actions by members of the committee will be approved upon receipt of the affirmative vote of two-thirds of the votes present (including proportional votes by Regional Representatives) at any meeting at which a quorum is present.

Antitrust Guidelines

All persons attending or otherwise participating in a NERC committee meeting will act in accordance with NERC's Antitrust Compliance Guidelines at all times during the meeting.

Open Meetings

NERC committee meetings will be open to the public, except as noted below under Confidential Information.

Confidential Sessions

At the discretion of the CCC chair, a meeting or portion of a meeting may have attendance limited based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive information or confidential information to one or more parties. All hearings of compliance matters will be confidential sessions. Confidential information will only be disclosed as provided by NERC ROP 1500. Confidentiality agreements may also be applied, as necessary, to protect sensitive information or confidential information.

Types of Meetings

Meetings may be conducted in person, by conference call, or by other means. The procedures contained in this manual will apply to all meetings regardless of how they are conducted.

Majority and Minority Views

All members of a committee will be given the opportunity to provide alternative views on an issue. The results of committee actions, including recorded minutes, will reflect the majority as well as any minority views of the committee members. The chair will communicate both the majority and any minority views in presenting results to the Board.

Action Without a Meeting

Two-thirds Majority

Any action required or permitted at a meeting of the committee may be taken without a meeting if two-thirds of the total votes available to the members of the CCC (including the proportional votes available to Regional Representatives) approve taking the action outside of a meeting.

Procedure

Such action without a meeting will be performed by mail or electronic ballot (e.g., telephone, fax, email, or Internet) and will be recorded in the minutes as a roll call ballot. The secretary will announce the action required at least 10 days before the date on which the action is to be voted. As time permits, members should be allowed a window of 10 business days to vote. The secretary will provide the results of such an action within 10 business days of the close of the voting period.

Officers and Staff

General

Number of Positions

The committee will have two officers and one secretary.

Officers

The committee officers will be one chair and one vice chair.

Executive

The committee shall retain an Executive Committee consisting of the committee officers, subcommittee chairs, secretary, and the Director of Compliance Assurance.

Secretary

The NERC staff coordinator will serve as the committee's secretary.

Voting of Officers

The committee chair and vice chair are voting members of the committee.

Officers Nominated by the Nominating Subcommittee

The CCC Nominating Subcommittee will recommend a chair and a vice chair who are then appointed by the NERC Board for a two-year term. The term of the chair and the vice chair, except for the first year, will begin on July 1 and end on June 30.

Officers as Sector Representatives

The chair and vice chair are selected from the membership of the committee and, in addition to their chair or vice chair responsibilities, will continue to serve as a member for the sector for which they were appointed to the committee.

Chair

The chair will direct and provide general supervision of committee activities, including the following:

1. Coordinate the schedule of all committee meetings, including approval of meeting duration and location;
2. Develop committee agendas and rule on any deviation, addition, or deletion from a published agenda;
3. Preside at and manage committee meetings, including the nature and length of discussion, recognition of speakers and proxies, motions, and voting;
4. Will lead or direct the conduct of any hearings and the preparation of any adjudicatory documents by the committee under Section 408 of the NERC ROP;
5. Will ensure actions and undertakings by the committee under the NERC ROP Section 408 meet all applicable legal and due process requirements;
6. Will act as spokesperson for the committee at forums inside and outside of NERC; and
7. May attend meetings of the NERC Board when necessary to report to the Board on committee activities.

Vice Chair

The vice chair will assume the responsibilities of the chair under the following conditions:

1. At the discretion of the chair (for brief periods of time);

2. When the chair is absent or temporarily unable to perform the chair's duties; or
3. When the chair is permanently unavailable or unable to perform the chair's duties. In the case of a permanent change, the vice chair will continue to serve until a new chair is nominated and selected by the Board.

Staff Coordinator

A member of the NERC staff will be selected by NERC's Director of Compliance Assurance to serve as the staff coordinator and secretary of the committee. The staff coordinator is not a committee member and does not have a vote. Under the direction of the committee executive and applicable NERC bylaws, guidelines, and ROP, the staff coordinator will do the following:

1. Manage the day-to-day operation and business of the committee;
2. Prepare and distribute the notices of the committee meetings, prepare the meeting agenda, and prepare and distribute the minutes of the committee meetings; and
3. Act as the committee's parliamentarian.

Nominating Subcommittee

Appointment

The CCC will annually appoint a Nominating Subcommittee.

Five Members

The subcommittee will consist of five members nominated by the committee chair and approved by the committee. The chair of the subcommittee will be selected by the CCC chair from among the five subcommittee members.

Appointed Annually

The chair will appoint the subcommittee members at the first regular meeting of the committee of the calendar year.

Length of term

The subcommittee members will serve for up to 14 months or until a new Nominating Subcommittee is authorized, whichever is earlier.

Duties

In addition to the duties, rights, and privileges described elsewhere in this manual, members of the Nominating Subcommittee will:

1. Prepare a slate of committee officer candidates for submission to the NERC Board for approval, and
2. Prepare a slate of recommended individuals to fill designated committee vacancies as required.

Subordinate Groups

Committee Organization

The CCC organizational structure will be arranged as allowed in the NERC Bylaws to support a superior-subordinate hierarchy that is ordered as follows: a committee, a subcommittee, a working group, and a task force, with a committee being primary and a task force being quaternary.

Subgroups

The committee may establish subcommittees, working groups, and task forces as necessary. The committee chair may also form any of these subordinate groups on behalf of the committee. The committee will be the responsible sponsor of all subordinate subcommittees, working groups, or task forces it may create, or that its subordinate subcommittees and working groups may create. The committee will keep the Board informed of all groups subordinate to the committee.

Subcommittees

The committee may establish subcommittees to which the committee may delegate some of the committee's broadly defined continuing functions. The committee will approve the scope of each subcommittee it forms. The committee chair will appoint the subcommittee officers (typically a chair and a vice chair) for a specific term (generally two years). The subcommittee officers may be reappointed for up to two additional terms. The subcommittee will work within its assigned scope and be accountable for the responsibilities assigned to it by the committee. The formation of a subcommittee, due to the permanency of the subcommittee, will be approved by the Board.

Working Groups

The committee or any of its subcommittees may delegate specific continuing functions to a working group. The sponsoring committee or subcommittee will approve the scope of each working group it forms. The chair of the sponsoring committee or subcommittee will appoint the working group officers (typically a chair and a vice chair) for a specific term (generally two years). The working group officers may be reappointed for up to two additional terms. The sponsoring committee or subcommittee will conduct a "sunset" review of each working group every two years. The working group will be accountable for the responsibilities assigned to it by the committee or subcommittee and will, at all times, work within its assigned scope.

Task Forces

The committee, subcommittee, or working group may assign specific work of a finite duration to a task force. The sponsoring committee, subcommittee, or working group will approve the scope of each task force it forms. The chair of the sponsoring committee, subcommittee, or working group will appoint the task force officers (typically a chair and a vice chair). Each task force will have a finite duration, normally less than one year. The sponsoring group will review the task force scope at the end of the expected duration and at each subsequent meeting of the sponsoring group after that until the task force is retired. Action of the task force sponsoring group is required to continue the task force past its defined duration. The sponsoring group should consider promoting to a working group any task force that is required to work longer than one year.

Membership and Representation

The membership of each subcommittee, working group, and task force should be established to address the need for expertise and balance of interests. Each group's membership requirements will be defined within the group's approved scope.

As a general guide, the broader the group's scope, the more emphasis there should be on balancing of interests. Therefore, subcommittees would be expected to have the broadest representation of appropriate industry

sectors, while a task force may be more focused on simply having the necessary expertise, and a working group may be somewhere between.

Each member of a subordinate group, and its officers, will be appointed by the chair of the sponsoring committee or group.

To the extent subgroup membership is of a representative nature, recommendations for staffing of the group should be provided in a manner consistent with the principles outlined in the staffing of a committee, including the use of an open nominations process. Regional Entity representatives should be recommended by the Regional Entity and Canadian representatives by the Canadian Electricity Association.

Preference may also be given to representatives recommended by broadly-based industry associations.

To the extent that subgroup membership is based on providing requisite expertise, the chair of the sponsoring committee or group may appoint members based on the relevant technical qualifications.

Procedures

Subcommittees, working groups, and taskforces will conduct business in a manner consistent with all applicable sections of this manual and Robert's Rules of Order.

Hearings

General

The CCC will conduct hearings, as necessary, to fulfill its function of serving as the hearing body for any contest between NERC and a Regional Entity regarding NERC findings, penalties, or sanctions for violation(s) of Reliability Standard(s) by the Regional Entity as described in Section 408 of the NERC ROP.

Hearing Procedure

Unless specifically identified otherwise elsewhere in this charter, the CCC's hearing procedure shall follow the hearing procedure mandated and approved by jurisdictional authorities for use by NERC and the Regional Entities in the Compliance and Enforcement program.

Hearing Panel

The committee shall not have a standing hearing panel. When a hearing is to be conducted, the CCC shall select five members to serve as the adjudicatory panel for that hearing. Members to serve on the panel shall be selected by vote of a valid quorum of the committee. Voting members of the committee at arm's length from~~with little or no affiliation with~~ parties to the hearing may be nominated or volunteer to stand for selection to the hearing panel. One or more alternates may also be selected, as the committee deems appropriate for the circumstances. A member may serve on more than one panel concurrently. A panel is disbanded upon conclusion of the hearing proceedings for which it was formed.

Attachment A

CCC Membership Structure

Primary Sector	Sub-Sector	Number of Members	Full Voting	Proportional Voting	Non-Voting
Investor-Owned Utility		2	X		
State/Municipal Utility		2	X		
Cooperative Utility		2	X		
Federal or Provincial Utility/Federal Power Marketing Administration		2	X		
Transmission Dependent Utility		2	X		
Merchant Electricity Generator		2	X		
Electricity Marketer		2	X		
Large End-use Electricity Customer		2	X		
Small End-use Electricity Customer		2	X		
Independent System Operator/Regional Transmission Organization		2	X		
Regional Entity	FRCC	1		X	
	RFC	1		X	
	ERCOT	1		X	
	MRO	1		X	
	NPCC	1		X	
	SERC	1		X	
	SPP	1		X	
	WECC	1		X	
Government	U.S. State	2	X		
	U.S. Federal	2			X
	Canadian Provincial	1			X
	Canadian Federal	1			X
Total		**34**			

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Protection System Maintenance Reliability Standard	)	**Docket Nos. RM14-8-000 RD15-3-000 RM15-9-000**
North American Electric Reliability Corporation	)	
Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard	)	

MOTION TO DEFER IMPLEMENTATION AND REQUEST FOR SHORTENED RESPONSE PERIOD AND EXPEDITED ACTION

Pursuant to Rule 212 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. 385.212 (2015), the North American Electric Reliability Corporation ("NERC") respectfully requests that the Commission defer the implementation of Commission-approved Reliability Standards PRC-005-3, PRC-005-3(i), and PRC-005-4 from January 1, 2016[1] until after the Commission issues a final order on proposed Reliability Standard PRC-005-6, which is being filed concurrently with this motion.[2] For the reasons discussed below, NERC respectfully requests that the Commission shorten the period for responding to this motion to a period of seven (7) days and that the Commission consider this motion on an expedited timeframe, so that it may issue an order before December 14, 2015.

As noted, concurrently with this Motion, NERC is submitting for Commission approval a new version of the PRC-005 Reliability Standard: proposed Reliability Standard PRC-005-6.

[1] Under the approved PRC-005-4 implementation plan, PRC-005-4 will become effective on January 1, 2016, thereby retiring PRC-005-3 and PRC-005-3(i) before they ever become effective.

[2] In the alternative, as explained in that petition, NERC proposes approval of PRC-005-5, which reflects only those revisions necessary to ensure that the PRC-005 standard is applied consistently to dispersed generation resources in accordance with prior Commission-approved revisions to the PRC-005 standard.

NERC's proposed implementation plan for proposed Reliability Standard PRC-005-6 provides for the development of comprehensive Protection System Maintenance Programs that would address all new applicable systems in the approved and proposed versions of the PRC-005 Reliability Standards, thereby promoting reliability and the efficient use of ERO Enterprise and registered entity resources. Further, the proposed implementation plan would avoid uncertainty regarding the applicability of the PRC-005 standard to owners of dispersed generation resources following the January 1, 2016 effective date of PRC-005-4. NERC files the instant motion to avoid uncertainty and the patchwork implementation of requirements while the Commission considers PRC-005-6 and the proposed comprehensive implementation plan.

I. BACKGROUND

The PRC-005 Reliability Standard has been revised several times since its initial approval in Order No. 693[3] to incorporate interpretations, clarify applicability, and respond to Commission directives. Version PRC-005-2 combined four standards that addressed maintenance and testing of protection and control systems into one comprehensive Reliability standard that included specific minimum maintenance activities and maximum time intervals of testing Protection System components.[4] Version PRC-005-2(i), which revised PRC-005-2 to clarify the standard's applicability to dispersed generation resources, is the currently-enforceable version of the standard.[5] The Commission has also approved revisions to the standard in PRC-005-3, to address Automatic Reclosing;[6] PRC-005-3(i), to continue the dispersed generation

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

[4] The Commission approved Reliability Standard PRC-005-2 on December 19, 2013 in Order No. 793. *Protection System Maintenance Reliability Standard*, Order No. 793, 145 FERC ¶ 61,253 (2013).

[5] The Commission approved Reliability Standards PRC-005-2(i) and PRC-005-3(i) on May 29, 2015. Letter Order, *N. Am. Elec. Reliability Corp.*, 151 FERC ¶ 61,186 (2015).

[6] The Commission approved Reliability Standard PRC-005-3 on January 22, 2015 in Order No. 803. *Protection System Maintenance Reliability Standard*, Order No. 803, 150 FERC 61,039 (2015).

resources applicability revisions in PRC-005-2(i); and PRC-005-4, to address Sudden Pressure Relaying.[7] Additionally, proposed PRC-005-2(ii) and PRC-005-3(ii), which were developed as part of a larger project to revise the definition of "Remedial Action Scheme," are pending Commission approval.[8]

Beginning with PRC-005-2, PRC-005 implementation plans have provided a phased implementation approach. Depending on the type of device and specific requirement, implementation is divided into phases, requiring registered entities to gradually ensure compliance of a percentage of their devices until they reach 100% compliance. In the PRC-005-3 and PRC-005-4 implementation plans, NERC carried forward this phased approach. However, recognizing that entities would need a reasonable period of time to incorporate Automatic Reclosing and Sudden Pressure Relaying into their Protection System Maintenance Programs, these implementation plans also provided a phased approach for compliance based on the date of regulatory approval for the standard version that introduced these systems. To demonstrate, in the implementation plan for PRC-005-4, entities would be required to calculate their compliance dates for their Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components from the regulatory approval dates of PRC-005-2, PRC-005-3, and PRC-005-4, respectively.

Since the approval date of these PRC-005 standard versions, the NERC Board of Trustees has approved, and NERC is concurrently submitting with this motion, the proposed Reliability Standard PRC-005-6 for Commission approval. The proposed standard brings supervisory

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[7] The Commission approved Reliability Standard PRC-005-4 on September 17, 2015 in Order No. 813. *Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard*, Order No. 813, 152 FERC ¶ 61,199 (2015).

[8] Proposed Reliability Standards PRC-005-2(ii) and PRC-005-3(ii) and the associated implementation plan for the revised definition of Remedial Action Scheme are currently pending before the Commission in Docket No. RM15-13-000.

devices associated with applicable Automatic Reclosing in the scope of the PRC-005 standard in response to a Commission directive in Order No. 803.[9] Further, the proposed standard carries forward certain dispersed generation resources applicability revisions previously approved by the Commission in PRC-005-2(i) and PRC-005-3(i).

II. MOTION

NERC respectfully requests that the Commission defer implementation of approved Reliability Standards PRC-005-3, PRC-005-3(i), and PRC-005-4 and the corresponding revised definitions of "Protection System Maintenance Program."

As described above, multiple versions of the PRC-005 standard are now pending enforcement or Commission approval, creating a patchwork approach to implementation. Under the current approach, entities would be required to perform multiple successive revisions to their Protection System Maintenance Plans to address new in-scope systems introduced in each PRC-005 version. Updating these programs is expected to be a time consuming task for many entities, and there have been concerns regarding maintaining and auditing multiple program versions and compliance schedules.

NERC proposes to address these concerns by simplifying and streamlining the implementation of PRC-005 requirements for all newly-applicable systems in the proposed PRC-005-6 implementation plan. Specifically, the proposed PRC-005-6 implementation plan allows entities a reasonable period of time to develop comprehensive Protection System Maintenance Programs to address newly-applicable systems introduced in PRC-005-2(ii), PRC-005-3, PRC-005-3(i), PRC-005-3(ii), PRC-005-4, PRC-005-5, and PRC-005-6.[10] This approach better

[9] *See* Order No. 803 at P 31.

[10] The proposed PRC-005-6 implementation plan incorporates by reference the existing implementation schedule for Protection System Components made applicable by PRC-005-2 and PRC-005-2(i).

promotes reliability by allowing for a comprehensive consideration of all new devices subject to PRC-005, resulting in fewer misidentified or missed devices. This approach also promotes the efficient use of ERO Enterprise and entity resources by eliminating the need to develop and audit multiple revisions to Protection System Maintenance Programs.

Further, the proposed PRC-005-6 implementation plan, which provides for a direct transition from currently-effective PRC-005-2(i) to proposed PRC-005-6, avoids an unintended consequence associated with the scheduled January 1, 2016 effective date of PRC-005-4. Specifically, in May 2015, the Commission approved a series of revisions designed to address the applicability of the PRC-005 standard to owners of dispersed generation resources. The Commission approved these revisions in currently-effective version PRC-005-2(i) and pending PRC-005-3(i) to ensure continuity in future versions of the PRC-005 Reliability Standard.[11] These dispersed generation resources applicability revisions are reflected with only minor clarifying modifications in proposed PRC-005-6. However, these revisions are not reflected in PRC-005-4.[12]

Should PRC-005-4 be allowed to become effective on January 1, 2016, there could be significant uncertainty regarding the applicability of the PRC-005 standard to the individual dispersed generation resources excluded under currently-effective PRC-005-2(i) and the proposed, successor versions of the PRC-005 standard. This uncertainty would run contrary to

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[11] *See supra* n. 5 at n. 4 ("In the immediate proceeding, we approve the requested modifications to both the currently effective standard [PRC-005-2], and the approved but not yet effective version of the standard [PRC-005-3], to ensure continuity in the application of the provisions pertaining to dispersed generation.")

[12] As NERC noted in its petition for approval of PRC-005-4, NERC was then in the process of developing corresponding changes to PRC-005-4 (through the development of PRC-005-5) to address applicability to dispersed generation resources. *See Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-005-4*, Dkt. No. RM15-9-000 (Dec. 18, 2014) at 2-3.

both the Commission and NERC's clear intent that these dispersed generation resources revisions be reflected in future versions of the PRC-005 standard.

To avoid this uncertainty and the patchwork implementation of requirements for new applicability, NERC requests that the Commission grant this motion to defer implementation of the approved but not yet effective PRC-005 standard versions. Further, in light of the pending January 1, 2016 effective date of PRC-005-4, NERC requests that the Commission shorten the period to respond to this motion to seven days and act in an expedited timeframe. Should the Commission ultimately approve proposed PRC-005-6, NERC respectfully requests that the Commission continue to defer implementation until the effective date of PRC-005-6 to allow the PRC-005-6 implementation plan to operate as intended. However, should the Commission not approve proposed PRC-005-6, NERC requests that the Commission defer implementation of PRC-005-3, PRC-005-3(i), and PRC-005-4 an additional six months from the effective date of the Commission's order remanding the proposed standard to allow entities a reasonable amount of time to come into compliance.

III. CONCLUSION

For the reasons stated above, NERC respectfully requests that the Commission:

- defer the implementation of Commission-approved Reliability Standards PRC-005-3, PRC-005-3(i), and PRC-005-4 from January 1, 2016 until after the Commission issues a final order regarding proposed Reliability Standard PRC-005-6;
- shorten the period for responding to this motion to seven days; and
- consider this motion on an expedited timeframe, so that it may issue an order before December 14, 2015.

Respectfully submitted,

/s/ Lauren A. Perotti

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Counsel for the North American Electric Reliability Corporation

November 13, 2015

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding. Dated at Washington, D.C. this 13th day of November, 2015.

/s/ Lauren A. Perotti

Lauren A. Perotti

Counsel for the North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability	**)**	
Corporation	**)**	**Docket No. FA11-21-000**

COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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 2015, in accordance with the January 16 Order. This variance information was

[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 in open session at the October 28, 2015 meeting of the NERC Finance and Audit Committee. The unaudited report was accepted by the NERC Board of Trustees at its meeting on November 5, 2015.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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II. CONCLUSION

NERC respectfully requests that the Commission accept this filing as compliant with Section II.7(b)(i) of the Settlement Agreement and the Commission's January 16 Order in Docket No. FA11-21-000.

Respectfully submitted,

/s/ Meredith M. Jolivert

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Counsel for North American Electric Reliability Corporation

Dated: November 13, 2015

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 13th day of November, 2015.

/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 Results as of September 30, 2015

Through September, NERC was $3.9M, 7.7%, under its expense and fixed asset budget, including costs related to CRISP. As reflected in the table below, NERC is projecting to be approximately $590k, 0.9%, over budget at year end, after taking into account authorized use of operating reserves.

Excluding CRISP, NERC was $418k, 1.0%, under budget and is projecting to be approximately $1.8M, 3.1% over budget. The year-end over budget variance is primarily due to the authorized use of reserves for various expenditures which are noted below in more detail. The difference between the Q3 budget variance ($418k under budget) and the year-end projection ($1.8M over budget) is primarily due to a number of information technology expenditures that we anticipate making prior to year-end, but have not yet been incurred. These include costs associated with the document management program, E-ISAC physical separation, enterprise reporting software and compliance applications.

YTD Actual vs Budget and Annual Projection vs Budget
By Category – Including CRISP

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
TOTAL FUNDING	**$ 51,287,493**	**$ 50,753,028**	**$ 534,465**	**1.1%**	**$ 65,675,921**	**$ 67,371,264**	**$ (1,695,343)**	**-2.5%**
BUDGET - EXPENSES and FIXED ASSETS								
PERSONNEL EXPENSES	$ 26,766,274	$ 26,982,565	$ (216,291)	-0.8%	$ 35,901,685	$ 35,803,311	$ 98,374	0.3%
MEETINGS, TRAVEL and CONFERENCE CALLS	2,571,505	2,581,257	(9,752)	-0.4%	3,470,462	3,566,146	(95,684)	-2.7%
CONSULTANTS and CONTRACTS	8,229,860	10,985,797	(2,755,938)	-25.1%	14,100,239	14,311,466	(211,227)	-1.5%
RENT	2,138,711	2,240,831	(102,120)	-4.6%	2,877,749	2,987,777	(110,028)	-3.7%
OFFICE COSTS, PROFESSIONAL SERVICES and MISC.	4,196,079	4,673,314	(477,235)	-10.2%	5,895,014	6,231,108	(336,094)	-5.4%
Other Non-Operating Expenses	60,068	98,250	(38,182)	-38.9%	70,206	131,000	(60,794)	-46.4%
FIXED ASSET PURCHASES (excluding depreciation)	2,460,969	2,713,875	(252,906)	-9.3%	4,924,472	3,618,500	1,305,972	36.1%
TOTAL BUDGET	**$ 46,423,466**	**$ 50,275,890**	**$ (3,852,424)**	**-7.7%**	**$ 67,239,826**	**$ 66,649,308**	**$ 590,518**	**0.9%**
FTEs	**192.05**	**192.35**	**(0.30)**	**-0.2%**	**193.68**	**192.30**	**1.38**	**0.7%**

NERC VARIANCES - excluding CRISP

NERC was $418k, 1.0%, under budget but is projecting to be $1.8M, 3.1%, over budget at year end due primarily to the following previously reported items which required and received all necessary reserve authorizations:

(1) Consulting support for assessment studies regarding the EPA's proposed Clean Power Plan;
(2) Contract costs for multiple reliability tools and costs of a secure alert system that was anticipated to be replaced by another system at lower costs[1];
(3) Leasehold improvements in the Atlanta and DC offices, which were funded by reserves and approved by the FAC at their meeting in November, 2014;
(4) Capitalized software costs to begin development of the document management system for which reserve funding has been authorized; and
(5) The executive and employee compensation studies.

YTD Actual vs Budget and Annual Projection vs Budget
By Category – Excluding CRISP

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
TOTAL FUNDING	**$ 43,391,362**	**$ 43,383,048**	**$ 8,314**	**0.0%**	**$ 57,564,083**	**$ 57,550,142**	**$ 13,942**	**0.0%**
BUDGET - EXPENSES and FIXED ASSETS								
PERSONNEL EXPENSES	$ 26,548,272	$ 26,636,561	$ (88,289)	-0.3%	$ 35,442,306	$ 35,344,061	$ 98,245	0.3%
MEETINGS, TRAVEL and CONFERENCE CALLS	2,528,498	2,543,755	(15,257)	-0.6%	3,408,962	3,516,146	(107,184)	-3.0%
CONSULTANTS and CONTRACTS	5,321,241	5,236,256	84,984	1.6%	7,584,139	6,645,411	938,728	14.1%
RENT	2,138,711	2,240,831	(102,120)	-4.6%	2,877,749	2,987,777	(110,028)	-3.7%
OFFICE COSTS, PROFESSIONAL SERVICES and MISC.	4,109,417	4,182,063	(72,647)	-1.7%	5,403,532	5,576,108	(172,575)	-3.1%
Other Non-Operating Expenses	60,068	98,250	(38,182)	-38.9%	70,206	131,000	(60,794)	-46.4%
FIXED ASSET PURCHASES (excluding depreciation)	2,451,929	2,638,875	(186,946)	-7.1%	4,724,472	3,518,500	1,205,972	34.3%
TOTAL BUDGET	**$ 43,158,135**	**$ 43,576,591**	**$ (418,457)**	**-1.0%**	**$ 59,511,366**	**$ 57,719,003**	**$ 1,792,364**	**3.1%**
FTEs	**190.57**	**190.47**	**0.10**	**0.1%**	**191.80**	**190.42**	**1.38**	**0.7%**

[1] A replacement system is currently under evaluation.

Following is a brief summary of variances by major categories (excluding CRISP):

- Personnel expenses were under budget $88k, 0.3%, due to lower than budgeted benefits and retirement costs, offset by higher than budgeted employment agency fees and payroll taxes. Personnel expenses are projected to be $98k, 0.3%, over budget at year-end. For purposes of the year-end projection, the Q4 vacancy rate assumption for most staff members was reduced to 0%, which had the effect of increasing the projected FTEs to 191.80, 1.38 FTEs higher than budget, as well as increasing projected year-end personnel expense. The 2015 budget for personnel expenses and total FTEs included a 6% vacancy assumption to account for attrition and timing of hiring open positions. As we move through the year, we adjust this vacancy rate down to account for the declining impact of vacancies as the year progresses. Actual results may vary.
- Meeting, travel and conferencing expenses were collectively under budget $15k, 0.6%, through September, and are projected to be $107k, 3.0%, under budget at year-end. Travel expenses were under budget $43k through September, but are projected to be $83k under budget at year-end. Meetings expenses were over budget $60k through September, but are projected to be $4k under budget at year-end. Conference calls expense was $31k under budget and projected to be $21k under budget. The reduction in projected expenses from prior forecasts is in large part due to ongoing efforts by operating area management to further control these costs.
- Consultant and Contract expenses were $85k, 1.6%, over budget through September and projected to be $939k, 14.1%, over budget at year-end inclusive of the previously reported authorized use of reserves. The table below summarizes existing and projected over budget variances by department.
    - RAPA - Over budget $143k YTD and projected to be $187k over budget at year-end due to costs for consulting support for assessment studies regarding the EPA's proposed Clean Power Plan and added support for the Reliability Issues Steering Committee (RISC). The use of operating reserves received all required authorizations.
    - Reliability Risk Management – Over budget $703k YTD and projected to be $590k over budget at year-end due to higher than budgeted costs for multiple reliability tools, costs resulting from delays in the replacement of a secure alert system, and costs resulting from delays in the transition from NERCnet to the new network established by the Eastern Interconnection Data Sharing Network, Inc. Effective September 30th, all NERCnet connections were discontinued.
    - General and Administrative – The YTD actual and projected year-end over budget variance is related to the ERO effectiveness survey which began in 2014 and carried over into 2015 and was not budgeted in 2015.

- Compliance Assurance; E-ISAC; Training and Education; and Finance and Accounting - Under budget YTD due to timing difference between actual expenses incurred and the budget, which is allocated equally throughout the year.
- IT – Under budget YTD partially due to the timing difference between actual expenses incurred and the budget, and also due to the reallocation of funding budgeted in Consultants and Contracts to cover costs that will be recorded in fixed assets and travel.
- HR - Under budget $91k YTD but projected to be $189k over budget at year-end due to costs for the executive and employee compensation study.

Consultant and Contract Expenses
By Department

CONSULTANTS and CONTRACTS	Actual	Budget	Variance Over (Under)	Annual Projection	Annual Budget	Variance Over (Under)
COMPLIANCE ASSURANCE	$ 246,930	$ 291,001	$ (44,071)	$ 388,000	$ 388,000	$ -
RAPA	1,023,524	880,274	143,250	1,142,030	955,450	186,580
RRM	1,599,325	896,503	702,822	1,666,589	1,077,321	589,268
E-ISAC	682,853	817,600	(134,747)	1,154,080	1,090,135	63,945
TRAINING, EDUC and OP CERT	447,329	564,096	(116,767)	739,354	752,130	(12,776)
GEN & ADMIN	61,045	-	61,045	80,000	-	80,000
POLICY and EXTERNAL AFFAIRS	2,400	11,250	(8,850)	15,000	15,000	-
INFORMATION TECHNOLOGY	979,837	1,297,201	(317,364)	1,586,853	1,729,600	(142,747)
HUMAN RESOURCES	132,432	223,707	(91,275)	487,275	298,275	189,000
FINANCE and ACCOUNTING	145,565	254,624	(109,059)	324,958	339,500	(14,542)
TOTAL (excluding CRISP)	**$ 5,321,241**	**$ 5,236,256**	**$ 84,984**	**$ 7,584,139**	**$ 6,645,411**	**$ 938,728**

- Office Costs, Professional Services and Miscellaneous expenses were collectively $73k, 1.7%, under budget through September; projected to be $173k, 3.1%, under budget at year-end.
  - Office Costs were $229k, 9.3%, over budget and projected to be $142k, 4.3% over budget at year-end, primarily due to higher than budgeted software and computer maintenance costs and higher than budgeted subscription services.
  - Professional services were $286k, 16.9%, under budget through September and projected to be $313k, 13.8%, under budget at year-end, primarily due to lower projected outside counsel expense
- Other Non-Operating expenses were $38k, 38.9%, under budget through September, and are projected to be $61k, 46.4%, under budget at year-end due to lower than budgeted interest

expense related to the capital financing loan. As a result of budget under runs in 2014, management did not draw on the loan in 2014 as was planned when the 2015 budget was developed.

- Fixed Asset Purchases (excluding depreciation) were $187k, 7.1%, under budget through September and are projected to be $1.2M, 34.3%, over budget at year end due to (1) the document management implementation that was approved by the FAC and Board in May, 2015 and (2) leasehold improvements in the Atlanta and DC offices, which were funded by reserves and approved at the FAC in November, 2014. A number of significant projects that are built into the projection are under way, but have not been completed. These projects include document management, enhancements to the compliance database and standards balloting system, and replacement for the software application for industry access to GADS data.

CRISP VARIANCES

CRISP was $3.4M, 51.3% under budget through September, and is projected to be $1.2M, 13.5%, under budget at year-end, primarily due to lower than budgeted contract and consulting expense. When the 2015 budget was prepared, it was assumed that all CRISP contracts would be executed and associated expenses would be incurred in 2015. However, as previously reported, a portion of CRISP expenses that were budgeted in 2015 were incurred in 2014. Based upon 2015 contract costs, which were finalized after the 2015 budget was submitted to FERC, contract and consulting expense related to CRISP is projected to be $1.1M under budget in 2015. This will also reduce 2015 funding from CRISP participants since CRISP contractual provisions require funding to match actual costs. Any under runs in actual versus budgeted CRISP costs which are funded by CRISP participants will be credited to CRISP participants pursuant to the terms of the CRISP participant agreements.

OPERATING RESERVES – Current Balances

As of September 30, 2015, the balance in working capital and operating reserves was $11.5M, which was $6.4M higher than budget. As previously reported, this higher than budgeted reserve balance was the result of two factors that were not anticipated at the time the 2015 budget was approved:

(1) The reserve balance reflects $4.4M in CRISP reserves that are in addition to a $500k CRISP insurance reserve, due to timing differences between receipt of third-party funding for CRISP, which occurs at the beginning of the year, and expenses incurred throughout the year.
(2) The beginning balance in working capital and operating reserves was $1.9M higher than budgeted due to expense and fixed asset under runs in 2014. The actual 2015 beginning balance in working capital and operating reserves was $7.5M, based upon audited 2014 year-end results.
(3) The balances in the Future Obligations Reserve, the Operating Contingency Reserve, the System Operator Reserves, and CRISP Reserves as of September 30, were approximately $3.2M, $2.5M, $932k, and $4.9M respectively.

				September 30, 2015 Reserve Balances				
	Actual	Budget	Variance Over (Under)	Future Obligations Reserve	Operating Contingency Reserve	System Operator Reserves	***CRISP Reserves	Assessment Stabilization Reserve
2015 Beginning Reserve Balances	$ 7,460,907	$ 5,573,225	$ 1,887,682	$ 3,569,492	$ 2,011,402	$ 1,294,513	$ 585,500	$ -
Change in Reserves from Current Year Operations								
Change in Reserves from budgeted operations	5,271,965	477,138	4,794,826	62,000	1,197,189	(362,368)	4,375,144	
Approved use of reserves	(407,938)	-	(407,938)		(407,938)			
Capital Financing								
Proceeds from Financing Activities (non-current only)	-		-		-			
Debt Service	(316,250)	(670,248)	353,998		(316,250)			
Other adjustments to reserves**	(476,338)	(241,664)	(234,675)	(451,083)	60,245		(85,500)	
Reserve Balance	$ 11,532,346	$ 5,138,451	$ 6,393,894	$ 3,180,409	$ 2,544,648	$ 932,145	$ 4,875,144	$ -

**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,
***Represents 2015 CRISP funding billed, net of 2014 credits issued for budget under runs.

OPERATING RESERVES – Year End Projection

The current year-end projection in total operating reserves for 2015 is $6.2M, including $1.86M in the Operating Contingency Reserve, which is slightly below the $2.0M Operating Contingency Reserve balance included in the 2016 Business Plan and Budget. The projected use of operating reserves includes the following:

(1) $600k for a document management program (approved by the Board in May 2015)
(2) $597k for leasehold improvements (approved by the FAC in November 2014)
(3) $110k to study the EPA Clean Power Plan (approved by the CEO)
(4) $50k for higher than budgeted costs associated with GridEx III (approved by the CFAO)
(5) $174k for the executive and employee compensation study (approved by the CEO)
(6) $60k for RISC support (approved by CFAO)

				2015 Projected Year End Reserve Balances				
	2015 Projection	2015 Budget	Variance Over (Under)	Future Obligations Reserve	Operating Contingency Reserve	System Operator Reserves	***CRISP Reserves	Assessment Stabilization Reserve
2015 Beginning Reserve Balances	**$ 7,460,907**	**$ 5,573,225**	**$ 1,887,682**	**$ 3,569,492**	**$ 2,011,402**	**$ 1,294,513**	**$ 585,500**	**$ -**
Change in Reserves from Current Year Operations								
Change in Reserves from budgeted operations	(181,899)	721,956	(965,855)	62,000	343,620	(512,435)	(75,084)	
Approved use of reserves	(1,320,006)	-	(1,320,006)		(1,320,006)			
Capital Financing								
Proceeds from Financing Activities (non-current only)	1,266,667	1,266,667	-		1,266,667			
Debt Service	(421,667)	(893,664)	471,997		(421,667)			
Other adjustments to reserves**	(621,320)	(322,218)	(299,102)	(593,418)	(17,486)		(10,416)	
Reserve Balance	**$ 6,182,681**	**$ 6,345,966**	**$ (225,284)**	**$ 3,038,074**	**$ 1,862,530**	**$ 782,077**	**$ 500,000**	**$ -**

**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

***Represents 2015 CRISP funding billed, net of 2014 credits issued for budget under runs.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Statement of Activities and Fixed Assets Budget
(Unaudited)
For the period ended 09/30/2015

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
Funding								
Assessments	$ 41,481,281	$ 41,481,281	$ -		$ 55,308,375	$ 55,308,375	$ -	
Penalties	1,155,000	1,155,000	-		1,155,000	1,155,000	-	
Third-Party Funding (CRISP)	7,233,146	6,707,692	525,454		7,233,146	8,943,589	(1,710,443)	
Testing	1,167,083	1,252,502	(85,419)		1,670,000	1,670,000	-	
Services & Software	47,000	37,502	9,498		50,000	50,000	-	
Workshop Fees	196,952	116,800	80,152		250,040	241,300	8,740	
Interest	6,875	2,251	4,624		9,204	3,000	6,204	
Miscellaneous	156	-	156		156	-	156	
Total Funding	$ 51,287,493	$ 50,753,028	$ 534,465	1.1%	$ 65,675,921	$ 67,371,264	$ (1,695,343)	-2.5%
Expenses								
Personnel Expenses								
Salaries	$ 20,908,156	$ 20,685,509	$ 222,647		$ 28,157,784	$ 27,580,676	$ 577,108	
Payroll Taxes	1,484,799	1,428,189	56,609		1,820,933	1,673,628	147,305	
Employee Benefits	2,438,897	2,660,380	(221,483)		3,184,986	3,547,177	(362,191)	
Savings & Retirement	1,934,422	2,208,486	(274,064)		2,737,982	3,001,829	(263,847)	
Total Personnel Expenses	$ 26,766,274	$ 26,982,565	$ (216,291)	-0.8%	$ 35,901,685	$ 35,803,311	$ 98,374	0.3%
Meeting Expenses								
Meetings	$ 753,638	$ 694,154	$ 59,484		$ 1,046,283	$ 1,050,000	$ (3,717)	
Travel	1,618,512	1,652,538	(34,026)		2,135,600	2,203,395	(67,795)	
Conference Calls	199,355	234,565	(35,210)		288,579	312,751	(24,172)	
Total Meeting Expenses	$ 2,571,505	$ 2,581,257	$ (9,752)	-0.4%	$ 3,470,462	$ 3,566,146	$ (95,684)	-2.7%
Operating Expenses								
Consultants and Contracts	$ 8,229,860	$ 10,985,797	$ (2,755,938)		$ 14,100,239	$ 14,311,466	$ (211,227)	
Rent & Improvements	2,138,711	2,240,831	(102,120)		2,877,749	2,987,777	(110,028)	
Office Costs	2,689,058	2,687,477	1,581		3,721,919	3,583,328	138,591	
Professional Services	1,495,583	1,958,462	(462,879)		2,137,845	2,611,280	(473,435)	
Miscellaneous	11,438	27,375	(15,937)		35,250	36,500	(1,250)	
Depreciation	1,472,302	1,749,755	(277,453)		2,284,218	2,333,006	(48,788)	
Total Operating Expenses	$ 16,036,952	$ 19,649,698	$ (3,612,746)	-18.4%	$ 25,157,220	$ 25,863,357	$ (706,138)	-2.7%
Other Non-Operating Expenses	$ 60,068	$ 98,250	$ (38,182)	-38.9%	$ 70,206	$ 131,000	$ (60,794)	-46.4%
Indirect Expenses	$ -	$ -	$ -		$ -	$ -	$ -	
Total Expenses	$ 45,434,799	$ 49,311,770	$ (3,876,972)	-7.9%	$ 64,599,572	$ 65,363,815	$ (764,242)	-1.2%
Net Change in Assets	**$ 5,852,694**	**$ 1,441,258**	**$ 4,411,437**	**306.1%**	**$ 1,076,348**	**$ 2,007,449**	**$ (931,101)**	**-46.4%**
Fixed Assets								
Depreciation	$ (1,472,302)	$ (1,749,755)	$ 277,453		$ (2,284,218)	$ (2,333,006)	$ 48,788	
Computer & Software	1,156,124	2,365,125	(1,209,001)		3,254,761	3,153,500	101,261	
Furniture & Fixtures	193,216	-	193,216		193,216	-	193,216	
Equipment	897,780	348,750	549,030		1,088,740	465,000	623,740	
Leasehold Improvements	213,849	-	213,849		387,756	-	387,756	
Allocation of Fixed Assets	-	-	-		-	-	-	
Incr(Dec) in Fixed Assets	**$ 988,667**	**$ 964,120**	**$ 24,547**	**2.5%**	**$ 2,640,254**	**$ 1,285,494**	**$ 1,354,760**	**105.4%**
Total Budget (Expenses plus Incr(Dec) in Fixed Assets)	**$ 46,423,466**	**$ 50,275,890**	**$ (3,852,424)**	**-7.7%**	**$ 67,239,826**	**$ 66,649,308**	**$ 590,518**	**0.9%**
FTE's	**192.05**	**192.35**	**(0.30)**	**-0.2%**	**193.68**	**192.30**	**1.38**	**0.7%**

NORTH AMERICAN ELECTRIC RELIABILITY COPORATION
STATEMENT OF FINANCIAL POSITION
(Unaudited)

	Unaudited 9/30/2015	Audited 12/31/2014	Working Capital and Operating Reserves 9/30/2015	Working Capital and Operating Reserves 12/31/2014
ASSETS				
Cash	$ 42,856,028	$ 38,904,711	$ 42,856,028	$ 38,904,711
Accounts receivable, net of allowance for uncollectible accounts of $0	15,667,168	5,059,002	15,667,168	5,059,002
Prepaid expenses and other current assets	1,110,902	756,727	1,110,902	756,727
Security deposit	125,416	99,136		
Employee Fiduciary - 457b	522,756	522,756		
457(f) Non-Qualified Def Comp	271,200	-		
Property and equipment	6,916,412	5,929,365		
Total Assets	$ 67,469,882	$ 51,271,697		
LIABILITIES AND NET ASSETS				
Liabilities				
Current Portion				
Accounts payable and accrued expenses (includes vacation accrual)	$ 4,257,317	$ 4,970,198	$ (4,257,317)	$ (4,970,198)
Accured incentive compensation	3,133,453	4,054,329	(3,133,453)	(4,054,329)
Deferred rent-current	252,933	249,269	(252,933)	(249,269)
Deferred compensation - current	14,257	14,257	(14,257)	(14,257)
Capital lease obligations - current	56,457	56,457	(56,457)	(56,457)
Accrued retirement liabilities	1,533,228	1,907,562	(1,533,228)	(1,907,562)
Debt service - current portion	421,667	421,667	(421,667)	(421,667)
Deferred income	13,926,691	6,228,959	(13,926,691)	(6,228,959)
Deferred revenue - other	-			
Deferred revenue - penalties	-	-	-	-
Deferred revenue - CRISP	251,854	3,953,379	(251,854)	(3,953,379)
Regional assessments	20,543,894	11,438,455	(20,543,894)	(11,438,455)
Total Current Portion	$ 44,391,752	$ 33,294,532		
Long-Term Portion				
Deferred compensation[1]	782,848	783,446		
Long-Term Debt	140,556	456,806		
Deferred Rent-non-current	3,389,609	3,569,492		
CRISP Insurance Reserve	500,000	500,000		
Capital lease obligations - non-current	216,481	216,481		
Total Long-Term Portion	$ 5,029,494	$ 5,526,224		
Total Liabilities	$ 49,421,246	$ 38,820,756		
Net Assets - unrestricted	$ 14,338,636	$ 8,485,941		
Net Assets - restricted	3,710,000	3,965,000	(3,710,000)	(3,965,000)
Total Liabilities and Net Assets	$ 67,469,882	$ 51,271,697	$ 11,532,346	$ 7,460,907

[1]Includes 457b liability, life insurance for former executive, and retiree medical

Working Capital and Operating Reserves	**$ 11,532,346**	**$ 7,460,907**

Financial Covenants	
1 - WC & OR Balance to Debt Service Ratio > 1.2 to 1.0 (Working Capital / Debt Service)	27.35
2 - Liquidity to Debt Service Ratio > 1.5 to 1.0* (= Cash - Regional Assessments - Restricted Net Assets)	44.12

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

October 30, 2015

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Informational Filing, Assessment of Protection System Single Points of Failure
Docket No. RM10-6-000

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits to the Federal Energy Regulatory Commission ("Commission") for informational purposes a report titled *Order No. 754*[1] *Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* ("Assessment"). The Assessment was prepared by two subcommittees of the NERC Planning Committee: the System Protection and Control Subcommittee ("SPCS") and the System Analysis and Modeling Subcommittee ("SAMS").

The Assessment presents a detailed analysis of the data collected through a Request for Data or Information[2] that required Transmission Planners, working with the Generator Owners, Transmission Owners, and Distribution Providers within their transmission planning areas, to assess their portion of the Bulk Electric System for locations at which a three-phase fault accompanied by a protection system failure could result in a potential reliability risk. NERC informed the Commission that it had initiated a Request

[1] In Order No. 754, the Commission expressed its concern that there was an issue concerning the study of a single point of failure on protection systems. To address this issue, the Commission directed FERC staff to meet with NERC and its appropriate subject matter experts to explore this reliability concern. The Commission also directed NERC to submit an informational filing within six months explaining whether there is a further system protection issue that needs to be addressed and if so, what forum and process should be used to address it and what priority it should be afforded. *See Interpretation of Transmission Planning Reliability Standard*, Order No. 754, 136 FERC ¶ 61,186 at PP 19-20 (2011).

[2] Request for Data or Information: Order No. 754 Single Point of Failure on Protection Systems (Aug. 16, 2012), *available at* http://www.nerc.com/pa/Stand/Pages/order_754.aspx. The procedure governing Requests for Data or Information is contained in Section 1600 of the NERC Rules of Procedure, *available at* http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

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for Data or Information to determine the potential exposure to and reliability risk associated with the single point of failure concern in its March 15, 2012 informational filing in the above-captioned docket.[3]

As described in greater detail therein, the Assessment concludes that, although the risk from single point of failure is not an endemic problem and instances of single point of failure exposure are lower on higher voltage systems, there is a reliability risk associated with single points of failure in protection systems that warrants further action.[4]

To address the issues and recommendations contained in the Assessment, the SPCS and the SAMS developed a Standard Authorization Request to modify Reliability Standard TPL-001-4 Transmission System Planning Performance Requirements. On October 29, 2015, the NERC Standards Committee authorized the posting of this Standard Authorization Request for an informal comment period and authorized the solicitation of nominations to form a Standard Authorization Request drafting team for Project 2015-10: Single Points of Failure TPL-001.

NERC respectfully requests that the Commission accept this filing for informational purposes only.

Respectfully submitted,

/s/ Lauren A. Perotti

Lauren A. Perotti
Counsel for the North American Electric Reliability Corporation

cc: Official service list in Docket No. RM10-6-000

[3] *See Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754*, Docket. No. RM10-6-000 (filed Mar. 15, 2012).

[4] *See* Assessment at 11.

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 30th day of October, 2015.

/s/ Lauren A. Perotti

Lauren A. Perotti
Counsel for the North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

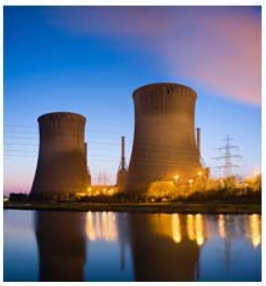
Order No. 754

Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request

System Protection and Control Subcommittee (SPCS) and
System Modeling and Analysis Subcommittee (SAMS)

September, 2015

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 NERC Reliability Standards;[1] 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" or "Commission") 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
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

[1] Capitalized terms include, but are not limited to the Glossary of Terms Used in NERC Reliability Standards. March 3, 2015. (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf) and Definitions Used in the NERC Rules of Procedure (ROP), Appendix 2. July 1, 2014. (http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_2_ROP_Definitions_20140701_updated_20140602.pdf).

Executive Summary

This report provides the results of an assessment of protection system single points of failure (SPF) in response to FERC Order No. 754,[2] including analysis of data from the NERC Section 1600 Request for Data or Information. Based on the analysis of data received, the report provides a discussion of alternatives to address this reliability concern and recommends a course of action to address the concern using a risk-based method.

Nearly 4,000 buses energized above 100kV were examined in detail. This is a comprehensive set of the key buses in the Bulk Electric System. This assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

Regarding single points of failure in protection systems, the System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) considered a variety of alternatives, and concluded that the most appropriate recommendation that aligns with O754 directives and maximizes reliability of protection system performance is to modify NERC Reliability Standard TPL-001-4 (*Transmission System Planning Performance Requirements*) through the NERC standards development process defined in the NERC Rules of Procedure. The recommended modifications address specifics of Protection System component failure, aspects of steady state and stability performance testing, and expansion of extreme event assessment requirements in order to minimize the potential risk of SPFs. Chapter 2 contains a discussion of alternatives considered. Specific guidance for modifying NERC Reliability Standard TPL-001-4 is provided in Chapter 3.

[2] *Interpretation of Transmission Planning Reliability Standard*, Order No. 754, 136 FERC ¶ 61,186 (2011) ("Order No. 754") (http://www.ferc.gov/whats-new/comm-meet/2011/091511/E-4.pdf).

Introduction

Objective

The objective of this assessment is to determine whether there is a reliability concern that NERC should address regarding the study of single points of failure on protection systems and, if so, what forum and process should be used to address the issue. This report provides the results of a comprehensive assessment of the study of data from the NERC Section 1600 Request for Data or Information collected in response to FERC Order No. 754. Based on the analysis of data, there is some degree of elevated reliability risk from SPF in certain key instances. The report provides discussion of alternatives to address this reliability concern and recommends a course of action to address the concern using a risk-based method.

Background

The issue of protection system failures brought to the forefront potential reliability concerns in Requirement R1.3.10 of the NERC transmission planning Reliability Standard TPL-002-0b (*System Performance Following Loss of a Single Bulk Electric System Element (Category B)*). The concern relevant to this assessment is whether Requirement R1.3.10 requires the study of protection system failures as part of Category B disturbances.

In FERC Order No. 754, issued September 15, 2011, the Commission agreed with commenters that this issue does not have to be addressed in TPL-002-0b, Requirement R1.3.10. However, the Commission also stated their belief that there is "an issue concerning the study of the non-operation of non-redundant primary protection systems; e.g., the study of a single point of failure on protection systems."[3] To address this concern, the Commission directed FERC staff to meet with NERC and its appropriate subject matter experts to explore the reliability concern, including where it can best be addressed, and identify any additional actions necessary to address the matter.

To satisfy the directive, a FERC Technical Conference was held October 24–25, 2011, to facilitate an open exchange among FERC staff, NERC staff, and industry stakeholders. One outcome of the FERC Technical Conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing whether single points of failure in protection systems pose a reliability concern. NERC staff worked with the SPCS and SAMS to develop a request for data or information under Section 1600 of the NERC Rules of Procedure[4] (the "Data Request" or "Order No. 754 Data Request"). The NERC Board of Trustees approved the Data Request on August 16, 2012.

The responsible Functional Entities ("entities") have submitted data to NERC for buses operated at 100 kV and above. Data is presented in Appendix A of this report according to voltage range (100–199 kV, 200–299 kV, 300–399 kV, 400–599 kV, and 600 kV or higher). The SPCS and SAMS have reviewed the submitted data, which provides statistical information on the number of buses at which a protection system single point of failure could result in an adverse impact to reliability of the bulk power system. The data also indicates the extent to which exposure to single points of failure exists at these buses, broken down by specific component categories of a protection system.

The assessment of this data set forms the basis for identifying the risk associated with protection system single points of failure, development of alternatives to address associated concerns, and subsequently a recommendation of the preferred alternatives to address the associated concerns.

[3] Id. at P.19.

[4] (http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20140701_updated_20140602%20(updated).pdf

Chapter 1 – Analysis of Data

Order No. 754 Data Request

Overview

The Order No. 754 Data Request[5] required that Transmission Planners, working with the Generator Owners, Transmission Owners, and Distribution Providers within their transmission planning areas, assess their portion of the Bulk Electric System (BES) for locations at which a three-phase fault accompanied by a protection system failure could result in a potential reliability risk. To accomplish this task in an effective and efficient manner, the SPCS and SAMS developed a method that entities could follow to create the statistics associated with this Data Request. Entities were permitted to use an alternate method, including combining steps, skipping steps, or reordering steps, to minimize burden based on their particular circumstances, and could use information from existing studies and existing assessments of protection systems in developing responses to the data request. For example, TPL-004-0a (*System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)*) simulations from transmission planning assessments could be used in developing responses to the Data Request.

Entities that followed an alternate method or utilized existing studies and existing assessments of protection systems in developing responses were required to provide a complete subset of buses containing both of the following characteristics:

- The bus has at least one Element for which the protection system does not fully meet the redundancy attributes for all component categories of Table B (from the data request), "Protection System Attributes
- Planning studies simulating a three phase fault, show that clearing times resulting from a single point failure of at least one protection system on an Element connected to that bus will result in system performance exhibiting one of the adverse impacts identified in Table C (from the data request), "Performance Measures."

The process of using differing methodologies to obtain this list of buses results in inconsistencies in the specific numbers of Protection Systems and buses evaluated in the various tables of Protection System attributes.

The Data Request included criteria to limit the assessment to a sample of buses using qualitative criteria that identified and included the buses more likely to have a more significant stability impact on the bulk power system. See Table 1.1 below, which is Table A from the Data Request.

[5] Request for Data or Information: Order No. 754 Single Point of Failure on Protection Systems, August 16, 2012.

Table 1.1: Criteria for Buses to be Tested
Buses operated at 200 kV or higher with 4 or more circuits
Buses operated at 100 kV to 200 kV with 6 or more circuits
Buses operated at 100 kV or higher that directly supply off-site power to a nuclear generating station
Any additional buses operated at 100 kV or higher that the Transmission Planner believes are necessary for the reliable operation of the bulk power system

For the buses meeting the Table 1.1 criteria, the Transmission Planner assessed the system performance for a three-phase fault accompanied by a protection system failure. For the purposes of the Data Request, Transmission Planners were to simulate clearing, based on the remote protection that would operate for the bus fault. The Transmission Planners were not to simulate operation of any local protection with the exception of local breaker failure protection (where provided) in instances where a single trip coil was the only single point of failure for protection systems on all Elements connected to the bus. In these cases, operation of the breaker failure protection was allowed in the simulation.

Following simulation of the events described above, the Transmission Planner evaluated the system performance against criteria provided in the Data Request that the SPCS and SAMS believe are indicative of the potential for instability, uncontrolled separation, or cascading outages. The criteria are contained in Table 1.2 below, which is Table C from the Data Request.

Table 1.2: Performance Measures
1. Loss of synchronism of generating units totaling greater than 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections
2. Loss of synchronism between two portions of the system
3. Negatively damped oscillations

For buses where the simulated system performance exhibited one or more of the adverse system response characteristics in Table 1.2, the protection system owners (Generator Owners, Transmission Owners, and Distribution Providers owning the relevant protection systems) provided detailed information regarding the protection systems on all elements connected to the bus. The presence of single points of failure was then assessed at the component level of a protection system, which consists of protective relays, communication systems, AC current and voltage inputs, and DC control circuitry. It should be noted that in some instances stability simulations were conducted prior to any review of the actual applied Protection Systems, while in other instances, the protection system owners may have conducted a preliminary assessment of the initial list of buses prior to simulations being conducted. Protection system owners evaluated the components of a protection system against the attributes defined in Table 1.3 below, which is Table B from the Data Request.

Table 1.3: Protection System Attributes to be Evaluated
Protective Relays: The protection system includes two independent protective relays that are used to measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal condition.
Communication Systems: The protection system includes two independent communication channels and associated communication equipment when such communication between protective relays for communication-aided protection functions (i.e., pilot relaying systems) is needed to satisfy system performance required in NERC Reliability Standards TPL-002-0b and TPL-003-0a.
AC Current and Voltage Inputs: The protection system includes two independent AC current sources and related inputs, except that separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing can be used to satisfy this requirement; and includes two independent AC voltage sources and related inputs, except that separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device can be used to satisfy this requirement.
DC Control Circuitry: The protection system includes two independent DC control circuits with no common DC control circuitry, auxiliary relays, or circuit breaker trip coils. For the purpose of this data request the DC control circuitry does not include the station DC supply or the main DC distribution panel(s), but does include all the DC circuits used by the protection system to trip a breaker, including any DC control circuit (branch) fuses or breakers at the main DC distribution panel(s).

Data was collected separately for the station DC supply. This data was collected on DC supplies to all of the 3,916 buses that meet the Table A criteria. Station DC supply data was collected to assess the incidence of two station DC supplies as well as the level of monitoring for buses with only one station DC supply. See the station DC supply attributes to be reported in Table 1.4 below, which is Table D from the Data Request.

Table 1.4: Station DC Supply Attributes to be Reported
The protection system includes two independent station DC supplies
The protection system includes one station DC supply that is centrally monitored; if the station DC supply is a battery the monitoring includes alarms for both low voltage and a battery open condition
The protection system includes one station DC supply that is centrally monitored; the station DC supply is a battery and the monitoring does not include alarms for both low voltage and a battery open condition
The protection system includes one station DC supply that is not centrally monitored

Entities submitted data in a tabular format as described in the Data Request. The output of the collected data is collated in the following eight tables (see Appendix A).

- Table A.1 – Buses Evaluated by the Transmission Planner
- Table A.2 – Attributes of Evaluated Transmission Line Protection Systems
- Table A.3 – Attributes of Evaluated Transmission Transformer Protection Systems
- Table A.4 – Attributes of Evaluated Generator Step-Up Transformer Protection Systems
- Table A.5 – Attributes of Evaluated Step-Down Transformer Protection Systems
- Table A.6 – Attributes of Evaluated Shunt device Protection Systems
- Table A.7 – Attributes of Evaluated Bus Protection Systems
- Table A.8 – Station DC Supply Attributes

The data for each table, aggregated for all responding entities across North America, is presented in Appendix A. Row 4 of Table A.1 contains the subset of buses that contain at least one Protection System where a failure to trip due to an existing single point of failure would result in one of the performance issues listed in Table 1.2. The data in Tables A.2 through A.7 are dependent on the methodology used by the reporting entity in identifying the buses in Row 4 of Table A.1. The assessment in this report is based on extensive discussion recognizing the variability of the data. The SPCS and SAMS have recognized this variability in the following discussion of the data. While in some cases this variability prevents definitive quantitative statements, the SPCS and SAMS consider the data to be sufficient to draw valid conclusions based on a qualitative but technical assessment.

Table A.1: Buses Evaluated by the Transmission Planner

The data in Table A.1 provides general insight regarding the buses evaluated by the Transmission Planners and includes the following information for each voltage range:

1. the total number of buses,
2. the number of buses that met the Table 1.1 criteria (Data Request, Table A) for further review,
3. the number of buses that were evaluated using actual clearing times
4. the number of buses for which a simulation based on actual clearing times exhibited at least one of the adverse impacts in Table 1.2 (Data Request, Table C).

Table A of the Data Request included the criteria shown in Table 1.1 to focus the analysis on those buses more likely to have a significant impact on the stability of the bulk power system. Limiting the number of buses significantly reduced the effort required of responding entities while still providing NERC a data population sufficient to draw valid conclusions. The criteria in Table 1.1 included the number of circuits connected to the bus, whether the bus directly supplies off-site power to a nuclear generating station, and whether the Transmission Planner believes for any other reason that the bus is necessary for the reliable operation of the bulk power system. For the purpose of applying the Table 1.1 criteria, the number of circuits connected includes any elements that represent a significant source of fault current (i.e., transmission lines, transmission transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher, and generator step-up transformers connecting generating resources with aggregate gross nameplate rating greater than 20 MVA). These criteria resulted in a large enough sample of data to draw valid conclusions. This conclusion is based on both the number and percentage of buses in each voltage range that met the criteria in Table 1.1. At the high-voltage (HV) levels (up to 230 kV), entities tested over 1,000 buses in each voltage range. At the extra high-voltage (EHV) levels (greater than 230 kV), entities tested over one-half of the total number of buses.

The reporting entities identified the following numbers of buses meeting the requirements of Table A in the data request:

- 1,522 buses (7 percent of all buses) operated at 100–199 kV,
- 1,310 buses (34 percent of all buses) operated at 200–299 kV,
- 768 buses (57 percent of all buses) operated at 300–399 kV,
- 262 buses (67 percent of all buses) operated at 400–599 kV, and
- 54 buses (81 percent of all buses) operated at 600 kV and above.

Table 1.5: Buses Evaluated by the Transmission Planner

Row	Description	100-199 kV	200-299 kV	300-399 kV	400-599 kV	≥600 kV
1	Total number of buses in the transmission planning area	21,817	3,848	1,350	392	67
2	Total number of buses in the transmission planning area that meet the criteria in Table A, "Initial Criteria for Buses to be Tested"	1,522	1,310	768	262	54
	Percentage of buses in the transmission planning area that meet the criteria in Table A, "Initial Criteria for Buses to be Tested"	7%	34%	57%	67%	81%

In general, the short-circuit strength at a bus is indicative of the potential risk that a prolonged fault will impact reliable operation of the bulk power system. Therefore, on a qualitative basis, the set of buses that met the criteria in Table A is more likely to include buses at which a protection system single point of failure may result in an adverse impact to reliability of the bulk power system than the buses with fewer connected circuits.

Rows 3 and 4 of Table A.1 provide information on the number of buses evaluated based on maximum expected clearing times and the number of buses at which simulation of a three-phase fault and a protection system single point of failure indicate system performance that exhibits at least one of the adverse impacts in Table 1.2 of the Data Request. The adverse impacts are indicative of a risk to reliable operation of the bulk power system and include the following:

- loss of synchronism of generating units totaling greater than 2,000 MW or more in the Eastern or Western Interconnections, or 1,000 MW or more in the ERCOT or Québec Interconnections,
- loss of synchronism between two portions of the system, and
- negatively damped oscillations.

Although various equivalent methodologies were allowed, the data in Row 4 is essentially the number of buses with both a Table C performance issue and the presence of a Protection System with a single point failure issue. This may overstate the problem somewhat, as not all SPF result in a failure to trip, and that many SPF will result in actual clearing times that are less than those resulting from a bus fault. Never the less, viewing the data in rows 3 and 4 of Table 1.6 in relation to each other demonstrates that, in general, the probability that a failure of a

protection system to clear a fault will impact reliable operation exists and increases at higher voltages as shown in the table.

Table 1.6: Buses Evaluated by the Transmission Planner						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
3	Total number of buses evaluated by the Transmission Planner based on actual clearing times	716	813	356	164	44
4	Total number of buses evaluated by the Transmission Planner based on actual clearing times that resulted in system performance exhibiting any adverse impact defined in Table C, "Performance Measures"	160	316	212	101	43
	Percentage of buses evaluated by the Transmission Planner based on actual clearing times that resulted in system performance exhibiting any adverse impact defined in Table C, "Performance Measures"	22%	39%	60%	62%	98%

However, this information alone does not indicate a reliability concern. Assessment of this reliability concern is a function of both the potential consequence and the exposure to a single point of failure. Thus, it is necessary to analyze the Table A.1 data in conjunction with the protection system attributes data in Tables A.2–A.7.

Tables A.2–A.7 Data: Attributes of Evaluated Protection Systems

Data in Tables A.2–A.7 provides insight into the presence of single points of failure for various power system elements (transmission lines, transmission transformers, generator step-up transformers, step-down transformers, shunt devices, and buses). These tables provide information on the total number of protection systems evaluated, the number that contain a single point of failure, and the presence of single points of failure by components of a protection system: protective relays, communication systems, AC current and voltage inputs, and DC control circuitry (see Table 1.3). The data collected in Tables A.2-A.7 for DC control circuitry includes auxiliary relays and trip coils but excludes the station DC supply. Data for the station DC supply was collected separately in Table A.8.

The single points of failure reported in Tables A.2–A.7 are related to the buses at which the Transmission Planner identified a potential risk, based on simulation of a three-phase fault and protection system single point of failure using maximum expected clearing times. In developing the requested data, simulations performed by the Transmission Planners were based on the assumption that a component failure of a protection system associated with a single point of failure would, in all cases, result in a failure to trip. This assumption provided a conservative and uniform method for simulating faults. However, the impact of a single component failure will not always result in a protection system failure to trip, depending on the component that fails and the design of the overall protection system. This subject is discussed further for each component type in the following subsections of this report. The discussion of component types is arranged according to the perceived risk to reliability associated with

a single point of failure, based on the experience of the SPCS and SAMS members. Technical analysis relative risk of various categories of failure is included in the next section of this chapter.

DC Control Circuitry

A single point of failure in DC control circuitry will result in the failure of a given protection system to trip and, depending on its design and the location of the failure, may also result in a failure to initiate breaker failure protection.

As discussed at the 2011 FERC Technical Conference on single points of failure, the single point of failure concern originated in a NERC Alert[6] based on the negative outcomes of three significant events. The root cause of these three events was the failure of a single relay (an auxiliary relay or lockout relay). Auxiliary relays and lockout relays are included in the DC control circuitry protection system attribute. These relays are generally unmonitored devices and, thus, may fail and remain undetected until they are periodically tested. Auxiliary relay failures in designs that include use of a single auxiliary relay for multiple functions will result in prolonged fault duration, particularly where a single auxiliary relay is used for both tripping and breaker failure initiation.

Protective Relays

A single point of failure of a protective relay poses a similar exposure to prolonged fault duration as that of failure of a DC control circuit; however, the risk depends on the relay type and protection system design. Many protection system designs using electromechanical relays are configured such that a failure of one relay will be backed up to some degree by other relays (i.e., an electromechanical protection system design is typically is made up of multiple relays and more than one may respond to a given fault). Similar to an auxiliary relay, an electromechanical relay may fail and the failure may remain undetected until the relay is tested. On the other hand, microprocessor relay may be monitored through an entity's supervisory control and data acquisition (SCADA) system; thus, most failure modes can be detected and addressed, in which cases the risk to the system is reduced to a relatively short period of time.

Communication Systems

A single point of failure in a communication system poses a lower level of risk. The Data Request only analyzed communication equipment in protection systems where communication-aided protection is needed to satisfy the system performance required in NERC Reliability Standards. The risk associated with a given protection system is dependent on the protection system design. Depending on the protection system design, a single point of failure may result in a failure of the communication-aided system to initiate a high-speed trip (e.g., a permissive overreaching transfer trip scheme), in which case delayed tripping will occur. In other designs, a communication system failure will not prevent high-speed tripping (e.g., a directional comparison blocking scheme).

Communication systems, regardless of vintage or design, are typically monitored and alarmed via SCADA or tested periodically.

AC Current and Voltage Inputs

A single point of failure in AC current and voltage inputs poses a lower level of risk of failure to trip. Instrument transformers are generally more robust than the other components of a protection system analyzed in the Data Request. However, cable runs, fuses, and terminations have a similar susceptibility to failure as DC control circuitry.

In most cases, a current circuit failure will result in an imbalance, which may result in a trip. In differential or ground overcurrent applications on transmission lines, buses, transformers, or shunt devices, AC current input

[6] Industry Advisory, Protection System Single Point of Failure, March 30, 2009. (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf).

failure will typically cause a circuit to trip at a certain load or fault level. Additionally, where AC current input circuits are monitored via SCADA, loss of a current input may be identified by automated devices or dispatch personnel.

Most microprocessor relays alarm for a loss of potential via SCADA; thus, the time that failed equipment is connected to the system can be minimized. Most electromechanical relays that use voltage inputs are prone to tripping on loss of a single-phase voltage (the most common AC voltage input failure). Additionally, where AC voltage input circuits are monitored via SCADA, low voltage due to a circuit failure may be alarmed.

Overall Order 754 Data Interpretation

Below 600kV, simulated testing showed that the probability of a three-phase fault accompanied by a protection system failure could result in the adverse system impacts listed in Table 1.2. The probability of an adverse impact decreased as the voltage class was lowered. At these voltage levels, a significant percentage of protection systems included single points of failure. This data shows that the chance of an adverse system impact due to a single point of failure at buses as low as 100kV exists, and leads to the conclusion that some risk mitigating action must be taken.

Above 600kV, simulated testing showed that the probability of a three-phase fault accompanied by a protection system failure resulting in an adverse system impact was high. However, almost all protection system equipment was fully redundant at that voltage level. The data shows that the chance of an adverse system impact due to a single point of failure at 600 kV and above is low.

Chapter 2 – Alternatives

The SPCS and SAMS considered the following alternatives in order of preference for addressing reliability risks associated with single points of failure:

Standards Development Process

Modify Reliability Standard TPL-001-4 – Transmission System Planning Performance Requirements

- Modify footnote 13 to include, at a minimum, protective relays, DC control circuitry, and station DC supply
- Place additional emphasis on assessment of a three-phase fault and protection system failure
  - Keep as an extreme event, but require studies of instances of single points of failure
    - Provides assurance that areas where a three-phase fault accompanied by a single point of failure that will cause an adverse impact are identified and evaluated
  - Elevate to a planning event with its own system performance criteria
    - Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event
  - Keep as an extreme event with no change (other than footnote 13)
    - Does not provide assurance a three-phase fault with protection system failure is studied in planning assessments
- Include a Guidelines and Technical Basis section related to the revisions pertaining to the study of protection system failures

Create a New Standard Addressing the Study of Protection System Single Points of Failure

- Remove relay failure from TPL-001-4 and create a separate TPL (transmission planning) or PRC (protection and control) standard on the study of protection system single points of failure (including the same options as the previous alternative)
  - Accomplishes same objective as modifying TPL-001-4
  - Retaining in TPL-001 is more efficient and keeps all planning tests in one standard (i.e., reason for combining TPL-001 through TPL-004)

Create a New Standard Requiring Redundant Protection Systems on BES Elements

- Create protection system redundancy PRC standard requiring redundant protection systems for all BES Elements
  - Not an efficient way to address the problem (precludes other solutions)
  - Promotes a zero-defect approach rather than a risk-based approach

Reliability Guideline

- Provides insight into modeling protection system failures in planning assessments
- Provides insight into evaluation of risk of a single point of failure

- Does not provide assurance a three-phase fault with protection system failure is studied in all planning assessments

NERC Alert

- Raises awareness based on findings from the Data Request
- Does not provide assurance a three-phase fault with protection system failure is studied in all planning assessments

Chapter 3 – Conclusion

Analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. The analysis shows that the risk from single point of failure is not an endemic problem and instances of single point of failure exposure are lower on higher voltage systems. However, the risk is sufficient to warrant further action. Risk-based assessment should be used to identify protection systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a protection system single point of failure exists). Not all failures adversely affect reliable operation of the bulk power system. The reliability risk varies based on which component of a protection system fails.

Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5. From TPL-001-4, Part 4.5: If the analysis concludes there is cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

Any modifications to a NERC standard must be made through the NERC Standards Process under the NERC rules of Procedure. Regarding single points of failure in protection systems, the SPCS and SAMS make the following recommendations to a Standards Drafting Team that may be formed for modifying TPL-001-4.:

- 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."[7]
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[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."

[7] 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).

Appendix A – Order No. 754 Data

Table A.1: Buses Evaluated by the Transmission Planner						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of buses in the transmission planning area	21,817	3,848	1,350	392	67
2	Total number of buses in the transmission planning area that meet the criteria in Table A, "Initial Criteria for Buses to be Tested"	1,522	1,310	768	262	54
3	Total number of buses evaluated by the Transmission Planner based on actual clearing times	716	813	356	164	44
4	Total number of buses evaluated by the Transmission Planner based on actual clearing times that resulted in system performance exhibiting any adverse impact defined in Table C, "Performance Measures"	160	316	212	101	43

Table A.2: Attributes of Evaluated Transmission Line Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of transmission line terminals at which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	2,227	1,799	1,625	402	182
2	Number of transmission line terminals at which the protection system does not meet all of the specified protection system attributes for redundancy in Table B	1,190	996	227	270	12
3	Number of transmission line terminals at which the protection systems does not meet the specified protection system attributes for the protective relays	229	25	4	0	0
4	Number of transmission line terminals at which the protection systems does not meet the specified protection system attributes for the communication systems	364	301	42	7	0
5	Number of transmission line terminals at which the protection systems does not meet the specified protection system attributes for the AC current and voltage inputs	960	581	182	99	12
6	Number of transmission line terminals at which the protection system does not meet the specified protection system attributes for the DC control circuitry	785	642	42	205	0

Table A.3: Attributes of Evaluated Transmission Transformer Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of Transmission Transformers for which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	382	519	559	129	87
2	Number of transmission transformers for which the protection system does not meet all of the specified protection system attributes for redundancy in Table B	186	297	188	63	3
3	Number of transmission transformers for which the protection system does not meet the specified protection system attributes for the protective relays	66	92	121	12	3
4	Number of transmission transformers for which the protection system does not meet the specified protection system attributes for the AC current and voltage inputs	81	135	33	3	3
5	Number of transmission transformers for which the protection system does not meet the specified protection system attributes for the DC control circuitry	143	260	131	51	0

Table A.4: Attributes of Evaluated Generator Step-Up Transformer Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of generator step-up transformers for which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	251	315	167	52	29
2	Number of generator step-up transformers for which the protection system does not meet all of the specified protection system attributes for redundancy in Table B	127	151	27	16	0
3	Number of generator step-up transformers for which the protection system does not meet the specified protection system attributes for the protective relays	68	66	12	4	0
4	Number of generator step-up transformers for which the protection system does not meet the specified protection system attributes for the AC current and voltage inputs	79	60	15	1	0
5	Number of generator step-up transformers for which the protection system does not meet the specified protection system attributes for the DC control circuitry	107	118	13	13	0

Table A.5: Attributes of Evaluated Step-Down Transformer Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of step-down transformers for which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	345	182	32	11	0
2	Number of step-down transformers for which the protection system does not meet all of the specified protection system attributed s for redundancy in Table B	211	101	16	5	0
3	Number of step-down transformers for which the protection system does not meet the specified protection system attributes for the protective relays	62	25	6	4	0
4	Number of step-down transformers for which the protection system does not meet the specified protection system attributes for the AC current and voltage inputs	134	53	2	0	0
5	Number of step-down transformers for which the protection system does not meet the specified protection system attributes for the DC control circuitry	165	88	14	1	0

Table A.6: Attributes of Evaluated Shunt Device Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of shunt devices for which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	205	151	142	66	114
2	Number of shunt devices for which the protection system does not meet all of the specified protection system attributes for redundancy in Table B	90	83	38	48	0
3	Number of shunt devices for which the protection system does not meet the specified protection system attributes for the protective relays	65	19	5	8	0
4	Number of shunt devices for which the protection system does not meet the specified protection system attributes for the AC current and voltage inputs	71	44	12	3	0
5	Number of shunt devices for which the protection system does not meet the specified protection system attributes for the DC control circuitry	86	64	29	43	0

Table A.7: Attributes of Evaluated Bus Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of buses for which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	642	565	516	126	45
2	Number of buses for which the protection system does not meet all of the specified protection system attributes for redundancy in Table B	403	370	220	36	3
3	Number of buses for which the protection system does not meet the specified protection system attributes for the protective relays	342	268	188	8	2
4	Number of buses for which the protection system does not meet the specified protection system attributes for the AC current and voltage inputs	276	246	47	13	1
5	Number of buses for which the protection system does not meet the specified protection system attributes for the DC control circuitry	340	263	54	35	0

Table A.8: Station DC Supply Attributes						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Number of buses for which the station DC supply includes two independent DC supplies	548	528	590	154	54
2	Number of buses for which the station DC supply includes one DC supply that is centrally monitored, and if the station DC supply is a battery, includes alarms for both low voltage and a battery open condition	234	179	37	13	0
3	Number of buses for which the station DC supply includes one DC supply that is centrally monitored, the station DC supply is a battery, and the monitoring does not include alarms for both low voltage and a battery open condition	657	489	95	35	0
4	Number of buses for which the station DC supply includes one DC supply that is not centrally monitored	51	33	3	2	0

Note: The data in Table A.8 was collected on DC supplies for all of the 3,916 busses meeting the requirements of Table A in the data request. These are the buses in Row 2 of Table A.1.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD MOD-031-2

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November 13, 2015

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD MOD-031-2

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA"),[1] Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] and Order No. 804,[3] the North American Electric Reliability Corporation ("NERC")[4] hereby submits for Commission approval Reliability Standard MOD-031-2 – Demand and Energy Data.[5] NERC requests that the Commission approve the proposed Reliability Standard, provided in Exhibit A hereto, as just, reasonable, not unduly discriminatory, or preferential, and in the public interest. NERC also requests approval of (1) the associated Implementation Plan (Exhibit B) and (2) the retirement of Reliability Standard MOD-031-1. As required by Section 39.5(a) of the Commission's regulations,[6] this Petition presents the technical basis and purpose of the proposed Reliability Standard, a summary of the development history (Exhibit D), and a demonstration that

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1 16 U.S.C. § 824o (2006).

2 18 C.F.R. § 39.5 (2014).

3 *Demand and Energy Data Reliability Standard*, Order No. 804, 150 FERC ¶ 61,109 (2015).

4 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) ("ERO Certification Order").

5 Unless otherwise designated, all capitalized terms used herein 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.

6 18 C.F.R. § 39.5(a) (2013).

the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[7] (Exhibit C).

In Order No. 804, the Commission approved Reliability Standard MOD-031-1, which provides authority for Bulk Power System planners and operators to collect demand, energy, and related data to support reliability studies and assessments, and enumerates the responsibilities and obligations of requestors and respondents of that data.[8] The Commission also directed NERC to make certain modifications to that Reliability Standard.[9] As discussed below, consistent with the directives in Order No. 804, proposed Reliability Standard MOD-031-2 improves upon MOD-031-1 by clarifying the compliance obligations related to (1) providing data to Regional Entities, and (2) responding to a request for data subject to confidentiality restrictions.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[10]

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7 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

8 *See* Order No. 804 at PP 14-15.

9 *Id*. at P 16.

10 Persons to be included on the Commission's service list are identified by an asterisk.

II. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[11] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duty of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) 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.[12] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[13] Section 39.5(a) of the Commission's regulations requires the ERO to file for Commission 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 to make effective.[14]

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory, or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA and Section 39.5(c) of the Commission's regulations, the Commission must give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.[15]

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11 16 U.S.C. § 824o (2006).

12 *Id.* § 824o(b)(1).

13 *Id.* § 824o(d)(5).

14 18 C.F.R. § 39.5(a) (2012).

15 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[16] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[17] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards.[18] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders. Further, a vote of stakeholders and adoption by the NERC Board is required before NERC submits the Reliability Standard to the Commission for approval.

C. Order No. 804

In Order No. 804, the Commission approved Reliability Standard MOD-031-1, finding that the standard "should continue to provide planners and operators access to complete and accurate demand and energy data to allow such entities to conduct their own resource adequacy analyses to serve peak demand."[19] The Commission also found that Reliability Standard MOD-031-1 "should provide for consistent documentation and information sharing practices for demand and energy

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[16] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[17] The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[18] ERO Certification Order at P 250.

[19] Order No. 804 at P 14.

data, and promotes efficient planning practices across the industry and supports the identification of needed system reinforcements."[20]

While approving Reliability Standard MOD-031-1, the Commission also directed that NERC:

1. Develop a modification to MOD-031-1 to clarify that Planning Coordinators and Balancing Authorities must provide demand and energy data upon request of a Regional Entity, as necessary to support NERC's development of seasonal and long-term reliability assessments.

2. Consider the compliance obligations of an applicable entity upon receipt of a data request that seeks confidential data.

Providing Data to Regional Entities. In Order No. 804, the Commission noted that while MOD-031-1, Requirement R3 requires Planning Authorities and Balancing Authorities to provide the Demand and energy data they collect pursuant to Requirements R1 and R2 of the standard to the applicable Regional Entity, Requirement R3 does not also obligate Planning Authorities and Balancing Authorities to provide Demand and energy data they obtain through alternative mechanisms to the Regional Entities.[21] The Commission stated that "NERC has the statutory responsibility to conduct periodic assessments of the reliability and adequacy of the Bulk-Power System, and we believe that it is incumbent on users, owners and operators subject to compliance with section 215 of the FPA to provide the necessary data to support such assessments."[22] To that

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[20] Order No. 804 at P 15.

[21] *Id*. at P 18. As NERC explained in Docket No. RM14-12-000, Requirements R1 and R2 of MOD-031-1 provide Planning Coordinators and Balancing Authorities the authority to issue data requests for Demand and energy data, but do not require them to do so as they may have alternative mechanisms to attain the data. *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard MOD-031-1* at 22-23, Docket No. RM14-12-000 (May 13, 2014); *Comments of the North American Electric Reliability Corporation in Response to Notice of Proposed Rulemaking* at 2-3, Docket No. RM14-12-000 (Dec. 1, 2014) (MOD-031-1 NOPR Comments).

[22] Order No. 804 at P 18. In its MOD-031-1 NOPR Comments, NERC stated that while the intent of Requirement R3 was to require Planning Coordinators and Balancing Authorities to provide the necessary data to their Regional Entities to support NERC's development of seasonal and long-term reliability assessments irrespective of the mechanisms by which they obtain the data, a strict reading of Requirement R3 indicates that it applies only to data collected pursuant to MOD-031-1. MOD-031-1 NOPR Comments at 2-3. As such, NERC

end, the Commission directed NERC to develop a modification to MOD-031 to clarify that Planning Coordinators and Balancing Authorities must provide Demand and energy data to a Regional Entity, upon request, irrespective of whether that data is collected pursuant to the Reliability Standard or through alternative arrangements.[23]

Requests for Confidentiality Data. Reliability Standard MOD-031-1, Requirement R4 requires applicable entities, within 45 days of a request, to share their Demand and energy data with certain other entities to help ensure that planners and operators of the Bulk-Power System have access to complete and accurate data necessary to conduct their own resource adequacy assessments. If, however, providing some or all of the requested data would conflict with the applicable entity's confidentiality, regulatory or security requirements, Requirement R4, Part 4.1 stipulates that the entity need not provide the data; however, it must respond to the requesting entity, within 30 days of the request, specifying the data that is not being provided and on what basis.

In response to comments from the Edison Electric Institute ("EEI") related to "potential conflicts" between a transmission provider's obligation to provide data under MOD-031-1 and the transmission provider's confidentiality obligations under an OATT or other confidentiality restrictions, the Commission directed NERC to consider these issues during standard development and, as necessary, clarify the compliance obligations of an applicable entity upon receipt of a request for confidential data.[24]

committed to modify Requirement R3 to clarify that Planning Coordinators and Balancing Authorities must provide their demand and energy data to their Regional Entity whether that data is collected pursuant to MOD-031-1 or through alternative arrangements.

[23] Order No. 804 at P 18.

[24] *Id*. at PP 19-20.

D. Development of the Proposed Reliability Standard

As further described in Exhibit D hereto, following the issuance of Order No. 804, NERC initiated a standard development project to address the directives in Order No. 804. NERC posted a Standard Authorization Request for informal comment from April 16, 2015 through May 19, 2015. Using the same standard drafting team that developed Commission-approved Reliability Standard MOD-031-1, proposed MOD-031-2 was posted for a 45-day initial comment period and ballot on July 31, 2015. The initial ballot resulted in the requisite stakeholder approval, receiving a quorum of 85.57% and an approval of 87.36%. After addressing industry comments on the initial draft of the proposed Reliability Standard, NERC posted the proposed Reliability Standard for a final ballot, which received a quorum of 89.60% and approval of 90.01%. The NERC Board of Trustees adopted proposed Reliability Standard MOD-031-2 and the associated Implementation Plan on November 5, 2015.

III. JUSTIFICATION FOR APPROVAL

As discussed below and in Exhibit C, the proposed Reliability Standard satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory, or preferential, and in the public interest. The following section provides an explanation of the manner in which the proposed Reliability Standard addresses the directives in Order No. 804.

A. Proposed Modifications to Reliability Standard MOD-031

1) Providing Data to Regional Entities

Consistent with Order No. 804, proposed Reliability Standard MOD-031-2 modifies Requirement R3 to clarify that Planning Authorities and Balancing Authorities must provide Demand and energy data to their Regional Entity, upon request, whether the Planning Authority

or Balancing Authority collected that data pursuant to Reliability Standard MOD-031 or through alternative mechanisms. Specifically, proposed Requirement R3 states:

> The Planning Coordinator or the Balancing Authority shall provide the data listed under Requirement R1 Parts 1.3 through 1.5 for their area to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties.

In contrast, the Commission-approved version of MOD-031-1, Requirement R3 provides:

> The Planning Coordinator or the Balancing Authority shall provide the data *collected under Requirement R2* to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties.

Changing the phrase "collected under Requirement R2" to "listed under Requirement R1 Parts 1.3 through 1.5" clarifies that the requirement to provide data to a Regional Entity applies broadly to the Demand and energy data listed in Requirement R1, whether the data was collected pursuant to a data request under the standard or through alternative mechanisms. The proposed modification will help ensure that NERC and the Regional Entities have the necessary data to conduct reliability assessments.

2) Requests for Confidential Data

After considering EEI's comments on potential confidentiality conflicts, the standard drafting team modified Requirement R4 to clarify that an entity "shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; *unless providing the requested data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements*." (Emphasis added). The standard drafting team concluded that it could not anticipate all the various confidentiality restrictions that might apply to Demand and energy data and tailor the language of the requirement to account for every type of confidentiality restriction. Instead, in the Rationale for Requirement R4, appended to proposed MOD-031-2, the standard drafting team explained:

> The obligation to share data under Requirement R4 does not supersede or otherwise modify any of the Applicable Entity's existing confidentiality obligations. For instance, if an entity is prohibited from providing any of the requested data pursuant to confidentiality provisions of an Open Access Transmission Tariff or a contractual arrangement, Requirement R4 does not require the Applicable Entity to provide the data to a requesting entity. Rather, under Part 4.1, the Applicable Entity must simply provide written notification to the requesting entity that it will not be providing the data and the basis for not providing the data. If the Applicable Entity is subject to confidentiality obligations that allow the Applicable Entity to share the data only if certain conditions are met, the Applicable Entity shall ensure that those conditions are met within the 45-day time period provided in Requirement R4, communicate with the requesting entity regarding an extension of the 45-day time period so as to have additional time to meet all those conditions, or provide justification under Part 4.1 as to why those conditions cannot be met under the circumstances.

In short, if data is subject to a confidentiality restriction that prohibits the sharing of that data, the entity need not provide that data. It is the responsibility of each entity receiving a data request under Requirement R4, however, to understand any confidentiality obligations applicable to the requested data and act accordingly.

B. Enforceability of the Proposed Reliability Standards

The proposed Reliability Standard includes VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standard. The VRFs and VSLs for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment.

The proposed Reliability Standard also include measures that support each requirement by clearly identifying what is required and how the ERO will enforce the requirement. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[25]

[25] Order No. 672 at P 327.

IV. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed Reliability Standards to become effective as set forth in the proposed Implementation Plan, provided in Exhibit B hereto. The proposed Implementation Plan is designed to match the effective date of the proposed Reliability Standard with the effective date of MOD-031-1, while also ensuring that entities will have sufficient time to develop the necessary process to implement this standard following Commission approval. The Implementation Plan provides that proposed MOD-031-2 shall become effective on the later of the effective date of MOD-031-1 or the first day of the first calendar quarter that is six months after the date that this standard is approved.

V. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve

- the proposed Reliability Standard and associated elements included in Exhibit A;
- the proposed Implementation Plan included in Exhibit B; and
- the retirement of Commission-approved Reliability Standard MOD-031-1.

Respectfully submitted,

/s/ Shamai Elstein

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Counsel for the North American Electric Reliability Corporation

Date: November 13, 2015

Exhibit A

Proposed Reliability Standard

MOD-031-2 Clean Version

A. Introduction

1. Title: Demand and Energy Data

2. Number: MOD-031-2

3. Purpose: To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. Applicability:

4.1. Functional Entities:

4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "Planning Coordinator")

This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both "Planning Authority" and "Planning Coordinator."

4.1.2 Transmission Planner

4.1.3 Balancing Authority

4.1.4 Resource Planner

4.1.5 Load-Serving Entity

4.1.6 Distribution Provider

5. Effective Date

5.1. See the MOD-031-2 Implementation Plan.

6. Background:

To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, authority is needed to collect the applicable data.

The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management

performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

Data provided under this standard is generally considered confidential by Planning Coordinators and Balancing Authorities receiving the data. Furthermore, data reported to a Regional Entity is subject to the confidentiality provisions in Section 1500 of the North American Electric Reliability Corporation Rules of Procedure and is typically aggregated with data of other functional entities in a non-attributable manner. While this standard allows for the sharing of data necessary to perform certain reliability studies and assessments, any data received under this standard for which an applicable entity has made a claim of confidentiality should be maintained as confidential by the receiving entity.

B. Requirements and Measures

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any,

activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary,:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data listed under Requirement R1 Parts 1.3 through 1.5 for their area to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authority, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall not be required to alter the format in which it maintains or uses the data;
- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; unless providing the requested data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements

4.1. If the Applicable Entity does not provide data requested because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, 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.

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 Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.4.1 through part 1.4.5

			did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data requested, but did so after 75 days	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data requested, but did so after 80 days	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data requested, but did so after 85 days	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data requested prior to 91 days

			from the date of request but prior to 81 days from the date of the request.	from the date of request but prior to 86 days from the date of the request.	from the date of request but prior to 91 days from the date of the request.	or more from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 6, 2014	Adopted by the NERC Board of Trustees	
1	February 19, 2015	FERC order approving MOD-031-1	
2	November 5, 2015	Adopted by the NERC Board of Trustees	

Rationale

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

Rationale for R1:

Rationale for R1: To ensure that when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they identify the entities that must provide the data (Applicable Entity in part 1.1), the data to be provided (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions (e.g., temperature, humidity or wind speed), or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

Balancing Authorities are included here to reflect a practice in the WECC Region where BAs are the entity that perform this requirement in lieu of the PC.

Rationale for R2:

This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

Rationale for R3:

This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

Rationale for R4:

This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

The obligation to share data under Requirement R4 does not supersede or otherwise modify any of the Applicable Entity's existing confidentiality obligations. For instance, if an entity is prohibited from providing any of the requested data pursuant to confidentiality provisions of an Open Access Transmission Tariff or a contractual arrangement, Requirement R4 does not

require the Applicable Entity to provide the data to a requesting entity. Rather, under Part 4.1, the Applicable Entity must simply provide written notification to the requesting entity that it will not be providing the data and the basis for not providing the data. If the Applicable Entity is subject to confidentiality obligations that allow the Applicable Entity to share the data only if certain conditions are met, the Applicable Entity shall ensure that those conditions are met within the 45-day time period provided in Requirement R4, communicate with the requesting entity regarding an extension of the 45-day time period so as to meet all those conditions, or provide justification under Part 4.1 as to why those conditions cannot be met under the circumstances.

MOD-031-2 Redline Version

A. Introduction

1. **Title: Demand and Energy Data**

2. **Number: MOD-031-~~1~~2**

3. **Purpose:** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both "Planning Authority" and "Planning Coordinator."

   4.1.2 Transmission Planner

   4.1.3 Balancing Authority

   4.1.4 Resource Planner

   4.1.5 Load-Serving Entity

   4.1.6 Distribution Provider

5. **Effective Date**

   ~~**5.1.** MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 that is twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   5.1. See the MOD-031-2 Implementation Plan.

6. **Background:**

   To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, authority is needed to collect the applicable data.

The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

Data provided under this standard is generally considered confidential by Planning Coordinators and Balancing Authorities receiving the data. Furthermore, data reported to a Regional Entity is subject to the confidentiality provisions in Section 1500 of the North American Electric Reliability Corporation Rules of Procedure and is typically aggregated with data of other functional entities in a non-attributable manner. While this standard allows for the sharing of data necessary to perform certain reliability studies and assessments, any data received under this standard for which an applicable entity has made a claim of confidentiality should be maintained as confidential by the receiving entity.

B. Requirements and Measures

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather

normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any, activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary,:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data ~~collected~~listed under Requirement ~~R2~~R1 Parts 1.3 through 1.5 for their area to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authority, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall not be required to alter the format in which it maintains or uses the data;
- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; ~~and~~unless providing the requested data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements
- ~~shall not be required to alter the format in which it maintains or uses the data.~~

4.1. If the Applicable Entity does not provide data requested ~~under this requirement~~ because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the

requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, 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.

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 Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.4.1 through part 1.4.5

			did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data ~~collected under Requirement~~	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data ~~collected under Requirement~~	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data ~~collected under Requirement~~	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data ~~collected under Requirement R2~~requested prior to 91 days or more

			~~R2~~requested, but did so after 75 days from the date of request but prior to 81 days from the date of the request.	~~R2~~requested, but did so after 80 days from the date of request but prior to 86 days from the date of the request.	~~R2~~requested, but did so after 85 days from the date of request but prior to 91 days from the date of the request.	from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 6, 2014	Adopted by the NERC Board of Trustees~~.~~	
1	February 19, 2015	FERC order approving MOD-031-1	
2	November 5, 2015	Adopted by the NERC Board of Trustees	

Rationale

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

Rationale for R1:

Rationale for R1: To ensure that when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they identify the entities that must provide the data (Applicable Entity in part 1.1), the data to be provided (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions (e.g., temperature, humidity or wind speed), or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

Balancing Authorities are included here to reflect a practice in the WECC Region where BAs are the entity that perform this requirement in lieu of the PC.

Rationale for R2:

This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

Rationale for R3:

This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

Rationale for R4:

This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the ~~provisions outlined in Requirement R4 below.~~Applicable Entity's confidentiality, regulatory, or security requirements. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

The obligation to share data under Requirement R4 does not supersede or otherwise modify any of the Applicable Entity's existing confidentiality obligations. For instance, if an entity is prohibited from providing any of the requested data pursuant to confidentiality provisions of an Open Access Transmission Tariff or a contractual arrangement, Requirement R4 does not

require the Applicable Entity to provide the data to a requesting entity. Rather, under Part 4.1, the Applicable Entity must simply provide written notification to the requesting entity that it will not be providing the data and the basis for not providing the data. If the Applicable Entity is subject to confidentiality obligations that allow the Applicable Entity to share the data only if certain conditions are met, the Applicable Entity shall ensure that those conditions are met within the 45-day time period provided in Requirement R4, communicate with the requesting entity regarding an extension of the 45-day time period so as to meet all those conditions, or provide justification under Part 4.1 as to why those conditions cannot be met under the circumstances.

Exhibit B

Implementation Plan

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Implementation Plan

Project 2010-04.1 Demand and Energy Data

Implementation Plan for MOD-031-2 – Demand and Energy Data

Approvals Required

MOD-031-2 – Demand and Energy Data

Prerequisite Approvals

There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

N/A

Applicable Entities

Planning Coordinator and Planning Authority

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

MOD-031-2 shall become effective as follows:

The later of the effective date of MOD-031-1 or the first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities 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 later of the effective date of MOD-031-1 or the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification

The six-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements

MOD-031-1 shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-2 in the particular jurisdiction in which the new standard is becoming effective.

Exhibit C

Order No. 672 Criteria

EXHIBIT C

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

Proposed Reliability Standard MOD-031-2 achieves the specific reliability goal of ensuring that Demand and energy data necessary to support reliability assessments conducted by the ERO and Bulk-Power System planners and operators is available to such entities. The proposed Reliability Standard enumerates the responsibilities of applicable entities with respect to the provision and/or collection of Demand and energy data. By providing for consistent documentation and information sharing practices for the collection and aggregation of such data, proposed Reliability Standard MOD-031-1 promotes efficient planning practices and supports the identification of needed system reinforcements. The modifications in proposed MOD-031-2 clarify the compliance obligations related to (1) providing data to Regional Entities, and (2) responding to a request for data subject to confidentiality restrictions.

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at PP 321, 324.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed Reliability Standard applies to Planning Coordinators, Transmission Planners, Balancing Authorities, Resource Planners, Load Serving Entities and Distribution Providers. The proposed Reliability Standard clearly articulates the actions that such entities must take to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

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[3] Order No. 672 at PP 322, 325.

[4] Order No. 672 at P 326.

4. **A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.** [5]

The proposed Reliability Standard contains measures that support each requirement by clearly identifying what is required to demonstrate compliance. These measures help provide clarity regarding the manner in which the requirements will be enforced, and help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. **Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.**[6]

The proposed Reliability Standard achieves the reliability goal effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard clearly enumerates the responsibilities of applicable entities with respect to the provision and/or collection of Demand and energy data necessary to support reliability assessments.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.**[7]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard contains significant benefits for the Bulk-Power System. The requirements of the proposed Reliability Standard help ensure that

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5 Order No. 672 at P 327.

6 Order No. 672 at P 328.

7 Order No. 672 at P 329-30.

entities that conduct reliability assessments, which are fundamental to analyzing the reliability of the grid, have access to complete and accurate data necessary to conduct those assessments.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]**

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model. In fact, the proposed Reliability Standard supports the various ways in which Demand and energy data is collected across the continent.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]**

The proposed Reliability Standard has no undue negative impact on competition. The proposed Reliability Standard requires the same performance by each of the applicable Functional Entities in the provision or collection of Demand and energy data. The standard does not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

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[8] Order No. 672 at P 331.

[9] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC 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.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective date for the standard is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. This will allow applicable entities adequate time to ensure compliance with the requirements. The proposed effective date is explained in the proposed Implementation Plan, attached as Exhibit B.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. Exhibit F includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the Reliability Standards. These processes included, among other things, comment and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and final ballots achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

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[10] Order No. 672 at P 333.

[11] Order No. 672 at P 334.

[12] Order No. 672 at P 335.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

[13] Order No. 672 at P 323.

Exhibit D

Summary of Development History and Complete Record of Development

Summary of Development

Summary of Development History

The development record for proposed Reliability Standard MOD-031-2 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission must give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit E.

II. Standard Development History

A. Standard Authorization Request Development

To address the Commission's directives in Order No. 804,[2] NERC revised the Standard Authorization Request ("SAR") approved by the Standards Committee ("SC") for the development of Reliability Standard MOD-031-1. The revised SAR was posted for comment from April 16, 2015 through May 19, 2015 and was approved by the SC on July 28, 2015.

B. First Posting - Comment Period, Initial Ballot and Non-Binding Poll

Proposed Reliability Standard MOD-031-2 was posted for a 45-day comment period from July 31, 2015 through September 18, 2015 with an initial ballot held from September 9, 2015 through September 18, 2015. The initial ballot received 85.57% quorum, and 87.36% approval. The Non-Binding Poll for VRFs and VSLs received 82.90% quorum and 89.20% of supportive opinions. There were 28 sets of comments,

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

2 *Demand and Energy Data Standard*, Order No. 804, 150 FERC ¶ 61, 109 (2015).

including comments from approximately 93 different individuals and approximately 64 companies, representing 9 of the 10 industry segments.[3]

C. Final Ballot

After considering stakeholder comments, no substantive revisions were made to Proposed Reliability Standard MOD-031-2 and the standard was posted for a 10-final ballot period from October 6, 2015 through October 15, 2015. The proposed Reliability Standard received 89.60% quorum and 90.01% approval.

D. Board of Trustees Adoption

Proposed Reliability Standard MOD-031-2 was adopted by the NERC Board of Trustees on November 5, 2015.

[3] NERC, *Consideration of Comments*, Project 2010-04.1, (November 5, 2015), *available at* *http://www.nerc.com/pa/Stand/Project%202010041%20MOD031%20Order%20No%20804%20Directives%20DL/2010-04_1_MOD-031_FERC_Order_No_804_Directive_MOD-031-2_Consideration_of_Comments_10062015.pdf*.

Complete Record of Development

Project 2010-04.1 MOD-031 FERC Order No. 804 Directives

Related Files | 2010-04 Demand Data (MOD C)

Status

A final ballot for **MOD-031-2 – Demand and Energy Data** concluded **8 p.m. Eastern, Thursday, October 15, 2015.** The ballot results can be accessed via the links below. The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

FERC Order 804

The collection of demand projections requires coordination and collaboration between Planning Authorities (also referred to as "Planning Coordinators"), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will enhance the reliability of the BPS. Collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. This project will modify the language in Requirement R3 to clarify certain obligations to provide data to the Regional Entity and will also address the directive to consider the compliance obligations of an applicable entity upon receipt of a data request that seeks confidential information.

Standard(s) Affected: MOD-031-1 – Demand and Energy Data

Purpose / Industry Need

This project will modify the language in Requirement R3 to clarify certain obligations to provide data to the Regional Entity and will also address the directive to consider the compliance obligations of an applicable entity upon receipt of a data request that seeks confidential information.

Draft	Actions	Dates	Results	Consideration of Comments
Draft 1 MOD-031-2 Clean **(19)** | Redline to Last Posted **(20)** Implementation Plan **(21)**	Final Ballot Info **(22)** Vote	10/06/15 - 10/15/15	Summary **(23)** Ballot Results **(24)**	
Draft 1 MOD-031-2 Clean **(6)** | Redline to Last Approved **(7)** Implementation Plan **(8)**	Initial Ballot and Non-binding Poll Updated Info **(10)** Info **(11)** Vote	09/09/15 - 09/18/15	Summary **(14)** Ballot Results **(15)** Non-binding Poll Results **(16)**	
Supporting Materials Unofficial Comment Form (Word) **(9)**	Comment Period Info **(12)** Submit Comments	07/31/15 - 09/18/15	Comments Received **(17)**	Consideration of Comments **(18)**

Draft RSAW	Join Ballot Pools	07/31/15 - 08/31/15		
	Info **(13)** Send RSAW feedback to: RSAWfeedback@nerc.net	08/14/15 - 09/18/15		
SAR **(1)** **Supporting Materials** Unofficial Comment Form (Word) **(2)**	Comment Period Info **(3)** Submit Comments	04/16/15 - 05/19/15	Comments Received **(4)**	Consideration of Comments **(5)**

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Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Demand and Energy Data		
Date Submitted:	~~July 18, 2013~~ April 1, 2015		
SAR Requester Information			
Name:	Darrel Richardson		
Organization:	NERC		
Telephone:	609-613-1848	E-mail:	darrel.richardson@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Resolve FERC directives from FERC Order 693 and Order 804, incorporate lessons learned, update standards, and to incorporate initiatives such as results-based, performance-based, Paragraph 81, etc.
Purpose or Goal (How does this request propose to address the problem described above?):
This is a continuation of Project 2010-04 MOD C. The revised SAR language is shown in red to ensure clarity as to the purpose of this phase of the project. The pro forma standard consolidates the reliability

SAR Information
components of the existing standards. This phase of the project proposes to revise MOD-031-1 to resolve the two directives from FERC Order 804.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objectives are to address the outstanding directives from FERC Order 693 and Order 804, remove ambiguity from the requirements, and incorporate lessons learned.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
An informal development ad hoc group is presenting a pro forma standard that consolidates the existing MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1 and MOD-021-1 into a single standard. The collection of demand projections requires coordination and collaboration between Planning Authorities (also referred to as "Planning Coordinators"), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will enhance the reliability of the BPS. Collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. The pro forma standard requirements are currently placed within a new standard, MOD-031-1. This phase of the project proposes to resolve the two directives from FERC Order No. 804 to clarify (1) the obligations of the Planning Coordinator and Balancing Authority to provide data to their Regional Entity, and (2) the compliance obligations associated with requests for confidential information.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
~~Detailed description of this project can be found in the Technical White Paper of this SAR submittal package.~~ This phase of the project will modify the language in Requirement R3 to clarify certain obligations to provide data to the Regional Entity and will also address the Order 804 directive to consider the compliance obligations of an applicable entity upon receipt of a data request that seeks confidential information.

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.
☐ 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.

Reliability Functions		
☐	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.	
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

Reliability and Market Interface Principles	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
MOD-001-1a	Available Transmission System Capability
MOD-016-1.1	Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management
MOD-017-0.1	Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0	Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load
MOD-019-0.1	Reporting of Interruptible Demands and Direct Control Load Management
MOD-021-1	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts

Related SARs	
SAR ID	Explanation

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

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Unofficial Comment Form

Project 2010-04.1 MOD-031 FERC Order No. 804 Directives

MOD-031-2 Standard Authorization Request

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the Standard Authorization Request (SAR) recommendation to modify MOD-031-1 to address FERC Order No. 804 directives. Comments must be submitted by **8 p.m. Eastern Tuesday, May 19, 2015**.

Documents and information about this project are available on the project page. If you have questions, contact Senior Standards Developer, Darrel Richardson (via email), or at 609-613-1848.

Background Information

The collection of demand projections requires coordination and collaboration between Planning Authorities (also referred to as "Planning Coordinators"), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will enhance the reliability of the BPS. Collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. This project will modify the language in Requirement R3 to clarify certain obligations to provide data to the Regional Entity and will also address the directive to consider the compliance obligations of an applicable entity upon receipt of a data request that seeks confidential information.

Questions

1. Do you agree that MOD-031-1 Requirement R3 needs clarity regarding certain obligations to provide data to the Regional Entity? If not, please explain.

   Yes:

   No:

   Comments:

2. Do you agree that the standard needs additional clarity regarding the obligations of an applicable entity upon receipt of a data request that seeks confidential information? If not, please explain.

   Yes:

   No:

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-04.1 MOD-031 FERC Order No. 804 Directives Standard Authorization Request

Informal Comment Period Open through May 19, 2015

Commenting for this project is in the Standards Balloting & Commenting System (SBS)

Now Available

A 30-day informal comment period for the **Project 2010-04.1 MOD-031 FERC Order No. 804 Directives** Standard Authorization Request (SAR) is open through **8 p.m. Eastern, Tuesday, May 19, 2015**.

SBS Login, Registration, Validation and Permissions

To **comment** in the SBS, you must have a contributor, voter, or proxy role.

Commenting

Use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact Arielle Cunningham. An off-line, unofficial Word version of the comment form is posted on the project page.

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

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or by phone at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Survey Report

Survey Details

Name 2010-04.1 FERC Order 804 Directive | MOD-031 SAR

Description

Start Date 4/16/2015

End Date 5/19/2015

Associated Ballots

Survey Questions

1. Do you agree that MOD-031-1 Requirement R3 needs clarity regarding certain obligations to provide data to the Regional Entity? If not, please explain.

Yes

No

2. Do you agree that the standard needs additional clarity regarding the obligations of an applicable entity upon receipt of a data request that seeks confidential information? If not, please explain.

Yes
No

Responses By Question

1. Do you agree that MOD-031-1 Requirement R3 needs clarity regarding certain obligations to provide data to the Regional Entity? If not, please explain.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Dominion believes the current requirement clearly states which entities must provide data to the Regional Entity when requested. However, we also acknowledge the FERC directive to develop a modification to clarify certain obligations to provide data to the Regional Entity.

Document Name:

Likes: 0

Dislikes: 0

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

The SRC agrees that the Regions and the ERO should have access to the R1-defined data whether or not the data was obtained as a result of an ad hoc request.

The SRC also suggests that any revised requirement be clear that the

obligation is specific to the data defined in R1.3 to R1.5. Linking R3 to the specific data in R1 would clarify that the ERO and the Regions should not be inundated with specialized or ad hoc data that are unrelated to the ERO and Regional studies.

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Independent Electricity System Operator - NA - Not Applicable - NPCC

Selected Answer: Yes

Answer Comment:

We agree that the Responsible Entities should comply with the data request by the REs, but suggest that the data to be provided should be confined to those listed under R1 only rather than any data.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: No

Answer Comment:

R3 clearly states the PC or BA is to provide to the RE ***only*** the data collected under Requirement R2.

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment: ERCOT supports the SRC's comments in response to this survey.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

The SDT developing the changes should consider the data request requirements of TOP-003-2 – Operational Reliability Data, R2 for possible duplication. TOP-003-2, R2 requires the BA to create a documented specification for data collection.

Document Name:

Likes: 0

Dislikes: 0

---

faranak sarbaz - Los Angeles Department of Water and Power - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment: AEP believes that MOD-31-1 R3 is sufficiently clear as written.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: No

Answer Comment:

As commented on during the development of MOD-031-1, we believe that Requirement R3 should be removed from the standard. The authority of the ERO Enterprise to request demand and energy data for the purpose of preparing reliability assessments is sufficiently addressed by Sections

1600 and 800 of the NERC Rules of Procedure (ROP) -- at least within the portions of the United States that are described in 18 CFR 39.2(a). The procedural steps outlined in section 1602 of the NERC ROP are the preferred method for NERC (and Regional Entities) to follow when it needs to collect data from registered entities. Within this process, NERC must "make its case" when requesting data or information by providing a proposed request to FERC (for informational purposes) in advance of posting publicly, posting the proposed request for a forty-five (45) day public comment period, evaluating any comments received, making revisions following receipt of comments as deemed appropriate, and submitting the proposed request to the NERC Board of Trustees for authorization. Section 1602, Part 2.2.1 also describes the minimum information that NERC shall provide for a proposed request. This process provides greater transparency for registered entities and other stakeholders.

Our position is that reliability assessments prepared by the ERO Enterprise, while informative, do not pose a significant threat to reliability of the Bulk-Power System in their absence. Provisions for NERC to request, and registered entities to provide, demand and energy data are therefore appropriately covered in the NERC ROP and should not be part of a Reliability Standard requirement. Therefore, our recommendation for addressing this FERC directive is to remove Requirement R3 from MOD-031-1.

Document Name:

Likes: 0

Dislikes: 0

Teresa Czyz - Georgia Transmission Corporation - 1 - SERC

Selected Answer: No

Answer Comment:

GTC agrees with the comments provided by ACES Power:

We believe that Requirement R3 is a classic Paragraph 81 requirement and should be retired in its entirety. Requirement R3 clearly meets criteria B1 – Administrative and B2 – Data Collection/Data Retention. The requirement meets criteria B1 and B2 because it is administrative in nature, requires the documentation of prior events (i.e. historical load) and "should be collected via some other method under NERC's rule and processes." NERC has a whole host of other data collection processes available via the Rules of Procedure (ROP) that are more efficient because they do not require compliance monitoring. As an example, a standing ROP Section 1600 data request could be used for NERC to gather load forecast data from BAs and PCs. Furthermore, there is already a precedent to use this data collection tool in the collection of TADS and GADS data. The bottom line is that this data is easily available to the Regional Entities without the need for Requirement R3.

While we understand that NERC must comply with the FERC directive to clarify R3, FERC allows alternative approaches that address their concerns that are equally as efficient and effective. Striking the requirement in its entirety with an explanation in the filing regarding how NERC and the Regional Entities use the ROP section 1600 data requests to gather demand and energy data to support NERC's development of seasonal and long-term reliability assessments would clearly meet an equally efficient and effective alternative. In fact, it is a superior approach to gathering the data because it does not involve compliance monitoring staff resulting in efficiency gains. This would especially hold true given that the Regional Entities or NERC have always been able to gather timely demand and energy data for the development of reliability assessments. Is Requirement R3's purpose to document part of the seasonal and long-term reliability assessment processes?

To further support the retirement of Requirement R3, we point to

NERC's initiatives to focus on the biggest risks to reliability of the Bulk Power System (BPS). NERC has developed risk elements to assist each Regional Entity in assessing risk and data submittals are categorized as low risk. We cannot support the revision of R3, as we feel that not only does it meet P81 criteria and there are equally efficient and effective alternatives to the requirement, but also it would be a low risk element that would not be monitored anyway. We urge the standard drafting teams to review requirements under the new approach of risk based compliance monitoring and enforcement to determine if the requirements that are being proposed will mitigate moderate to high risks to the BPS. In this case, R3 will not mitigate moderate or high risks and should be retired.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

If an auditor were to choose to penalize an entity for obtaining the data through some method less burdensome than an R1 data request, that would be ridiculous. But common sense does not always prevail, so I suppose that means that clarification is necessary. MOD timelines should be flexible/recognize when data requests become subject to corporate confidentiality procedures.

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We agree that the Responsible Entities should comply with the data request by the Regional Entities, but suggest that the data to be provided should be confined to that listed under R1 only rather than any data. The data request should be limited to that data necessary to support NERC's development of seasonal and long-term reliability assessments [FERC Order 804 paragraph 18].

The detailed description of the SAR says a modification of requirement R3 will occur. The SAR should allow for a separate requirement to be developed. This may be necessary because the data collection process may be via an alternative collection mechanism other than R2.

Document Name:

Likes: 0

Dislikes: 0

Michael Lowman - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Duke Energy agrees that clarification is needed.

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We believe that Requirement R3 is a classic Paragraph 81 requirement and should be retired in its entirety. Requirement R3 clearly meets criteria B1 – Administrative and B2 – Data Collection/Data Retention. The requirement meets criteria B1 and B2 because it is administrative in nature, requires the documentation of prior events (i.e. historical load) and "should be collected via some other method under NERC's rule and processes." NERC has a whole host of other data collection processes available via the Rules of Procedure (ROP) that are more efficient because they do not require compliance monitoring. As an

example, a standing ROP Section 1600 data request could be used for NERC to gather load forecast data from BAs and PCs. Furthermore, there is already a precedent to use this data collection tool in the collection of TADS and GADS data. The bottom line is that this data is easily available to the Regional Entities without the need for Requirement R3.

While we understand that NERC must comply with the FERC directive to clarify R3, FERC allows alternative approaches that address their concerns that are equally as efficient and effective. Striking the requirement in its entirety with an explanation in the filing regarding how NERC and the Regional Entities use the ROP section 1600 data requests to gather demand and energy data to support NERC's development of seasonal and long-term reliability assessments would clearly meet an equally efficient and effective alternative. In fact, it is a superior approach to gathering the data because it does not involve compliance monitoring staff resulting in efficiency gains. This would especially hold true given that the Regional Entities or NERC have always been able to gather timely demand and energy data for the development of reliability assessments. Is Requirement R3's purpose to document part of the seasonal and long-term reliability assessment processes?

To further support the retirement of Requirement R3, we point to NERC's initiatives to focus on the biggest risks to reliability of the Bulk Power System (BPS). NERC has developed risk elements to assist each Regional Entity in assessing risk and data submittals are categorized as low risk. We cannot support the revision of R3, as we feel that not only does it meet P81 criteria and there are equally efficient and effective alternatives to the requirement, but also it would be a low risk element that would not be monitored anyway. We urge the standard drafting teams to review requirements under the new approach of risk based compliance monitoring and enforcement to determine if the requirements that are being proposed will mitigate moderate to high risks to the BPS. In this case, R3 will not mitigate moderate or high risks and should be retired.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Texas RE recommends providing clarity in order to deter entities from activities that do not support reliability.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We would suggest to the drafting team to include in Requirement R3 some alternative language suggesting how to handling 'confidential' information appropriately and its listed as followed: 'The Planning Coordinator or the Balancing Authority shall provide the data collected (public and confidential should be handle appropriately) under Requirement R2 to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties'. Also, we would like the drafting team to add some clarity on whether the data request is applicable to the entities specific Regional Entity or can any Regional Entity request the data from the applicable Planning Coordinator or Balancing Authority?

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

BPA believes one does not need to give confidential information regarding individual entities when providing details about expected future conditions when looking at the entire electrical system. There may be times when the expected outcome is large enough that individual entities activities can be discerned. Given that planning must be done with confidential information, if clarifying language were provided, BPA suggests that it limits distribution of the data by the receiving entity and does not limit what is communicated - - or in other words, language that indicates all details or communication of the information must be directed to the organization that initiated the document.

Document Name:

Likes: 0

Dislikes: 0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer: No

Answer Comment:

Requirement 3 has sufficient clarity

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

2. Do you agree that the standard needs additional clarity regarding the obligations of an applicable entity upon receipt of a data request that seeks confidential information? If not, please explain.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Dominion believes that NERC's Rules of Procedure, Section 1500 adequately addresses this.

Document Name:

Likes: 0

Dislikes: 0

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

The SRC submits that Requirements R2 and R4 should be revised to provide that the requested data shall be returned to the Applicable Entity subject confidentiality requirements and agreements. This clarification would ensure that entities explore all possible avenues for provision of data that could be deemed confidential prior to exercising its right to refuse provision under Requirement 4.1.

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Independent Electricity System Operator - NA - Not Applicable - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: No

Answer Comment:

CPS Energy believes that 4.1 provides the Applicable Entity sufficient rights to refuse to provide the data under 1) failure of the requesting entity to provide a "demonstrated need" for the data or 2) providing the data would confict with the Applicable Entity's confidentiality, regulatory, or security requirements.

Document Name:

Likes: 0

Dislikes: 0

---

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the SRC's comments in response to this survey.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

---

faranak sarbaz - Los Angeles Department of Water and Power - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

MOD-031-1 replaces a number of other MOD standards where the topic of confidential information was not explicitly addressed. AEP believes that MOD-031-1 R4.1 is sufficiently clear as written in regards to the obligations of an applicable entity that receives a request for potentially confidential information.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

In light of our recommendation to remove Requirement R3 from the

MOD-031 Reliability Standard (see response to question #1), the emphasis of the standard will primarily be directed at the authority of the Planning Coordinator or Balancing Authority to request demand and energy data from the other applicable entities (Transmission Planner, Resource Planner, Load-Serving Entity, and Distribution Provider) for the purpose of supporting reliability studies and assessments that are performed by the Planning Coordinator or Balancing Authority. If there are no pre-existing agreements that address data confidentiality between the requesting entity (Planning Coordinator or Balancing Authority) and the submitting entity (Transmission Planner, Resource Planner, Load-Serving Entity, and Distribution Provider), we can understand that this may be a cause of concern with the submitting entity (Transmission Planner, Resource Planner, Load-Serving Entity, and Distribution Provider).

Document Name:

Likes: 0

Dislikes: 0

Teresa Czyz - Georgia Transmission Corporation - 1 - SERC

Selected Answer: Yes

Answer Comment:

Again, GTC agrees with the comments provided by ACES Power:

We agree additional clarity is needed and recommend removing redundancies in R4. First, R4 should be clarified so that no Resource Planner (RP) can request energy and demand data from another RP. There simply is no situation in which one RP needs another RP's data. This is a FERC standards of conduct issue as it deals with competition between RPs. Second, R4 should not include the PC and BA

as requesting entities since they will already be requesting data via R1. These two steps alone will eliminate the majority of the ambiguity and redundancy.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

I agree that confidential information disclosures require clarity in light of corporate customer data protection policies and the potential impact resolution of a policy compliant response has on the information request time requirements identified in the MOD. However, with requests at system level, conflicts occurences would be an infrequent exception.

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Lowman - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Duke Energy agrees that clarification is needed.

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We agree additional clarity is needed and recommend removing redundancies in R4. First, R4 should be clarified so that no Resource Planner (RP) can request energy and demand data from another RP. There simply is no situation in which one RP needs another RP's data. This is a FERC standards of conduct issue as it deals with competition between RPs. Second, R4 should not include the PC and BA as requesting entities since they will already be requesting data via R1. These two steps alone will eliminate the majority of the ambiguity and redundancy.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Texas RE recommends providing clarity in order to deter entities from activities that do not support reliability.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: No

Answer Comment: Exelon doesn't think the requirement needs clarification.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment: We agree there should be some type of clarity added to the standard in

reference to confidential information. At this point, the current language doesn't suggest the proper handling of confidential information by any of the applicable entities. We would suggest addressing the confidential piece in Requirement R2 where the applicable entities are requesting this type of data should verify potential confidential information and the entity providing this data marking the information as such 'confidential' so there is no confusion on how this data should be handled. We also suggest to the drafting team to mention in the requirement that the data being requested is pertaining to EIA-411 and this connection needs to be re-establish on what type of data is being requested.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

BPA believes to properly plan you must provide some confidential information generically.

Document Name:

Likes: 0

Dislikes: 0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer: No

Answer Comment:

No additional clarity is needed.

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2010-04.1 FERC Order 804 Directive | MOD-031 SAR

Comment Period Start Date: 4/16/2015

Comment Period End Date: 5/19/2015

The Industry Segments are:
1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Full Name	Entity Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Region	Group Member Segment(s)
Jason Marshall	ACES Power Marketing	6	MRO,WECC,TRE,SERC,SPP ,RFC	ACES Standards Collaborators	Bob Solomon	Hoosier Energy	RFC	1
					Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
					Ginger Mercier	Prairie Power	SERC	1,3
					James Manning	North Carolina Electric Membership Corporation	SERC	3,4,5
					Ryan Strom	Buckeye Power	RFC	3,4,5

					Michael Brytowski	Great River Energy	MRO	1,3,5,6
					Shari Heino	Brazos Electric Power Cooperative	TRE	1,5
					Amber Skillern	East Kentucky Power Cooperative	SERC	1,3
					Bill Watson	Old Dominion Electric Cooperative	SERC	3,4
					Bill Watson	Old Dominion Electric Cooperative	SERC	3,4
Kaleb Brimhall	Colorado Springs Utilities	5		Colorado Springs Utilities	Shawna Speer	Colorado Springs Utilities	WECC	1
					Charlie Morgan			3
					Shannon Fair			6
					Kaleb Brimhall			5
Louis Slade	Dominion - Dominion Resources, Inc.	6		Dominion NCP	Mike Garton	NERC Compliance Policy	NPCC	5,6
					Randi Heise		SERC	1,3,5,6

					Connie Lowe		SERC	1,3,5,6
					Louis Slade		RFC	5,6
Michael Lowman	Duke Energy	1,3,5,6	FRCC,SERC,RFC	Mike Lowman on Behalf of Duke Energy	Doug Hils	Duke Energy	RFC	1
					Lee Schuster		FRCC	3
					Dale Goodwine		SERC	5
					Greg Cecil		RFC	6
Emily Rousseau	MRO	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
					Amy Casucelli	Xcel Energy		1,3,5,6
					Chuck Lawrence	American Transmission Company		1
					Chuck Wicklund	Otter Tail Power Company		1,3,5
					Theresa Allard	Minnkota Power Cooperative, Inc		1,3,5,6
					Dave Rudolph	Basin Electric Power Cooperative		1,3,5,6
					Kayleigh Wilkerson	Lincoln Electric System		1,3,5,6

					Jodi Jenson	Western Area Power Administration		1,6
					Larry Heckert	Alliant Energy		4
					Mahmood Safi	Omaha Public Utility District		1,3,5,6
					Marie Knox	Midwest ISO Inc.		2
					Mike Brytowski	Great River Energy		1,3,5,6
					Randi Nyholm	Minnesota Power		1,5
					Scott Nickels	Rochester Public Utilities		4
					Terry Harbour	MidAmerican Energy Company		1,3,5,6
					Tom Breene	Wisconsin Public Service Corporation		3,4,5,6
					Tony Eddleman	Nebraska Public Power District		1,3,5
Lee Pedowicz	Northeast Power	10	NPCC	NPCC--Project 2010-	Alan Adamson	New York State	NPCC	10

	Coordinating Council			04.1 MOD-031		Reliability Council, LLC		
					David Burke	Orange and Rockland Utilities Inc.		3
					Greg Campoli	New York Independent System Operator		2
					Sylvain Clermont	Hydro-Quebec TransEnergie		1
					Kelly Dash	Consolidated Edison Co. of New York, Inc.		1
					Gerry Dunbar	Northeast Power Coordinating Council		10
					Kathleen Goodman	ISO - New England		2
					Mark Kenny	Northeast Utilities		1
					Helen Lainis	Independent Electricity System Operator		2

					Alan MacNaughton	New Brunswick Power Corporation		9
					Paul Malozewski	Hydro One Networks Inc.		1
					Bruce Metruck	New York Power Authority		6
					Lee Pedowicz	Northeast Power Coordinating Council		10
					Robert Pellegrini	The United Illuminating Company		1
					Si Truc Phan	Hydro-Quebec TransEnergie		1
					David Ramkalawan	Ontario Power Generation, Inc.		5
					Brian Robinson	Utility Services		8
					Wayne Sipperly	New York Power Authority		5

					Edward Bedder	Orange and Rockland Utilities Inc.		1
					Peter Yost	Consolidated Edison Co. of New York, Inc.		3
					Michael Jones	National Grid		1
					Brian Shanahan	National Grid		1
					Silvia Parada Mitchell	NextEra Energy, LLC		5
					Michael Forte	Consolidated Edison Co. of New York, Inc.		1
					Glen Smith	Entergy Services, Inc.		5
					Brian O'Boyle	Consolidated Edison Co. of New York, Inc.		8
					RuiDa Shu	Northeast Power Coordinating Council		10

					Connie Lowe	Dominion Resources Services, Inc.		5
Albert DiCaprio	PJM Interconnection, L.L.C.	2	RFC	ISO Standards Review Committee	Charles Yeung	SPP	SPP	2
					Ben Li	IESO	NPCC	
					Mark Holman	PJM	RFC	
					Kathleen Goodman	ISONE	NPCC	
					Greg Campoli	NYISO	NPCC	
					Christina V. Bigelow	ERCOT	TRE	
					Ali Miremadi	CAISO	WECC	
					Terry Bilke	MISO	RFC	
Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	SPP	2
					Joe Fultz	Grand River Dam Authority		1
					Kevin Giles	Westar Energy Inc		1,3,5,6
					James Nail	City of Independence, Missouri		3,5

					Dona Parks	Grand River Dam Authority		1
					Jason Smith	Southwest Power Pool Inc		2
					mike Kidwell	Empire District Electric Company		1,3,5
					Sean Simpson	Board of Public Utilities, City of McPherson	NA - Not Applicable	NA - Not Applicable

1. Do you agree that MOD-031-1 Requirement R3 needs clarity regarding certain obligations to provide data to the Regional Entity? If not, please explain.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Selected Answer: No

Answer Comment:

Dominion believes the current requirement clearly states which entities must provide data to the Regional Entity when requested. However, we also acknowledge the FERC directive to develop a modification to clarify certain obligations to provide data to the

Regional Entity.

Response: The SDT thanks you for your clarifying comment.

Likes: 0

Dislikes: 0

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Selected Answer: Yes

Answer Comment:

The SRC agrees that the Regions and the ERO should have access to the R1-defined data whether or not the data was obtained as a result of an ad hoc request.

The SRC also suggests that any revised requirement be clear that the obligation is specific to the data defined in R1.3 to R1.5. Linking R3 to the specific data in R1 would clarify that the ERO and the Regions should not be inundated with specialized or ad hoc data that are unrelated to the ERO and Regional studies.

Response: The SDT agrees with your comment and has made the corresponding modifications.

Likes: 0

Dislikes: 0

Mark Wilson - Independent Electricity System Operator - NA - Not Applicable - NPCC

Selected Answer: Yes

Answer Comment:

We agree that the Responsible Entities should comply with the data request by the REs, but suggest that the data to be provided should be confined to those listed under R1 only rather than any data.

Response: The SDT agrees with your comment and has made the corresponding modifications.

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes:	0

Brian Bartos - CPS Energy - 3 -

Selected Answer:	No
Answer Comment:	R3 clearly states the PC or BA is to provide to the RE ***only*** the data collected under Requirement R2.
Response:	The SDT thanks you for your clarifying comment.
Likes:	0
Dislikes:	0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:	Yes
Answer Comment:	ERCOT supports the SRC's comments in response to this survey.
Response:	The SDT agrees with your comment and has made the corresponding modifications.

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Selected Answer: Yes

Answer Comment:

The SDT developing the changes should consider the data request requirements of TOP-003-2 – Operational Reliability Data, R2 for possible duplication. TOP-003-2, R2 requires the BA to create a documented specification for data collection.

Response: The entire scope of the data that can be requested is within the standard and documented within the data request prepared pursuant to Requirement R1.

Likes: 0

Dislikes: 0

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faranak sarbaz - Los Angeles Department of Water and Power - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

AEP believes that MOD-31-1 R3 is sufficiently clear as written.

Response: The SDT thanks you for your clarifying comment.

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: No

Answer Comment:

As commented on during the development of MOD-031-1, we believe that Requirement R3 should be removed from the standard. The authority of the ERO Enterprise to request demand and energy data for the purpose of preparing reliability assessments is sufficiently addressed by Sections 1600 and 800 of the NERC Rules of Procedure

(ROP) -- at least within the portions of the United States that are described in 18 CFR 39.2(a). The procedural steps outlined in section 1602 of the NERC ROP are the preferred method for NERC (and Regional Entities) to follow when it needs to collect data from registered entities. Within this process, NERC must "make its case" when requesting data or information by providing a proposed request to FERC (for informational purposes) in advance of posting publicly, posting the proposed request for a forty-five (45) day public comment period, evaluating any comments received, making revisions following receipt of comments as deemed appropriate, and submitting the proposed request to the NERC Board of Trustees for authorization. Section 1602, Part 2.2.1 also describes the minimum information that NERC shall provide for a proposed request. This process provides greater transparency for registered entities and other stakeholders.

Our position is that reliability assessments prepared by the ERO Enterprise, while informative, do not pose a significant threat to reliability of the Bulk-Power System in their absence. Provisions for NERC to request, and registered entities to provide, demand and energy data are therefore appropriately covered in the NERC ROP and should not be part of a Reliability Standard requirement. Therefore, our recommendation for addressing this FERC directive is to remove Requirement R3 from MOD-031-1.

Response:

The SDT concluded that a standard was necessary. The standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent. Because certain Canadian provinces have adopted only select portions of the NERC Rules of Procedure, a standard is necessary to ensure that NERC and the Regional Entities has the authority to collect the necessary data from all applicable registered entities. The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment.

Likes: 0

Dislikes: 0

Teresa Czyz - Georgia Transmission Corporation - 1 - SERC

Selected Answer: No

Answer Comment:

GTC agrees with the comments provided by ACES Power:

We believe that Requirement R3 is a classic Paragraph 81 requirement and should be retired in its entirety. Requirement R3 clearly meets criteria B1 – Administrative and B2 – Data Collection/Data Retention. The requirement meets criteria B1 and B2 because it is administrative in nature, requires the documentation of prior events (i.e. historical load) and "should be collected via some other method under NERC's rule and processes." NERC has a whole host of other data collection processes available via the Rules of Procedure (ROP) that are more efficient because they do not require compliance monitoring. As an example, a standing ROP Section 1600 data request could be used for NERC to gather load forecast data from BAs and PCs. Furthermore, there is already a precedent to use this data collection tool in the collection of TADS and GADS data. The bottom line is that this data is easily available to the Regional Entities without the need for Requirement R3.

While we understand that NERC must comply with the FERC directive to clarify R3, FERC allows alternative approaches that address their concerns that are equally as efficient and effective. Striking the requirement in its entirety with an explanation in the filing regarding how NERC and the Regional Entities use the ROP section 1600 data requests to gather demand and energy data to support NERC's development of seasonal and long-term reliability assessments would clearly meet an equally efficient and effective alternative. In fact, it is a superior approach to gathering the data because it does not involve compliance monitoring staff resulting in efficiency gains. This would especially hold true given that the Regional Entities or NERC have always been able to gather timely demand and energy data for the development of reliability assessments. Is Requirement R3's purpose to document part of the seasonal and long-

term reliability assessment processes?

To further support the retirement of Requirement R3, we point to NERC's initiatives to focus on the biggest risks to reliability of the Bulk Power System (BPS). NERC has developed risk elements to assist each Regional Entity in assessing risk and data submittals are categorized as low risk. We cannot support the revision of R3, as we feel that not only does it meet P81 criteria and there are equally efficient and effective alternatives to the requirement, but also it would be a low risk element that would not be monitored anyway. We urge the standard drafting teams to review requirements under the new approach of risk based compliance monitoring and enforcement to determine if the requirements that are being proposed will mitigate moderate to high risks to the BPS. In this case, R3 will not mitigate moderate or high risks and should be retired.

Response:

The SDT concluded that a standard was necessary. The standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent. Because certain Canadian provinces have adopted only select portions of the NERC Rules of Procedure, a standard is necessary to ensure that NERC and the Regional Entities has the authority to collect the necessary data from all applicable registered entities. The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment.

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:	Yes
Answer Comment:	If an auditor were to choose to penalize an entity for obtaining the data through some method less burdensome than an R1 data request, that would be ridiculous. But common sense does not always prevail, so I suppose that means that clarification is necessary. MOD timelines should be flexible/recognize when data requests become subject to corporate confidentiality procedures.
Response:	The SDT has modified Requirement R3 to clearly state that an entity has to respond to a request from its Regional Entity regardless of how the data is collected. If there are known confidentiality issues they should be dealt with prior to the gathering of data since the scope of the data being requested is defined within the approved standard.
Likes:	0
Dislikes:	0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Selected Answer:	Yes
Answer Comment:	We agree that the Responsible Entities should comply with the data request by the Regional Entities, but suggest that the data to be provided should be confined to that listed under R1 only rather than any data. The data request should be limited to that data necessary to support NERC's development of seasonal and long-term reliability assessments [FERC Order 804 paragraph 18].

	The detailed description of the SAR says a modification of requirement R3 will occur. The SAR should allow for a separate requirement to be developed. This may be necessary because the data collection process may be via an alternative collection mechanism other than R2.
Response:	The SDT agrees with your comment and has made the corresponding modifications.
Likes:	0
Dislikes:	0

Michael Lowman - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Selected Answer:	Yes
Answer Comment:	**Duke Energy agrees that clarification is needed.**
Response:	The SDT agrees with your comment and has made the corresponding modifications.
Likes:	0
Dislikes:	0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Selected Answer: No

Answer Comment:

We believe that Requirement R3 is a classic Paragraph 81 requirement and should be retired in its entirety. Requirement R3 clearly meets criteria B1 – Administrative and B2 – Data Collection/Data Retention. The requirement meets criteria B1 and B2 because it is administrative in nature, requires the documentation of prior events (i.e. historical load) and "should be collected via some other method under NERC's rule and processes." NERC has a whole host of other data collection processes available via the Rules of Procedure (ROP) that are more efficient because they do not require compliance monitoring. As an example, a standing ROP Section 1600 data request could be used for NERC to gather load forecast data from BAs and PCs. Furthermore, there is already a precedent to use this data collection tool in the collection of TADS and GADS data. The bottom line is that this data is easily available to the Regional Entities without the need for Requirement R3.

While we understand that NERC must comply with the FERC directive to clarify R3, FERC allows alternative approaches that address their concerns that are equally as efficient and effective. Striking the requirement in its entirety with an explanation in the filing regarding how NERC and the Regional Entities use the ROP section 1600 data requests to gather demand and energy data to support NERC's development of seasonal and long-term reliability assessments would clearly meet an equally efficient and effective alternative. In fact, it is a superior approach to gathering the data because it does not involve compliance monitoring staff resulting in efficiency gains. This would especially hold true given that the Regional Entities or NERC have always been able to gather timely demand and energy data for the development of reliability assessments. Is Requirement R3's purpose to document part of the seasonal and long-term reliability assessment processes?

To further support the retirement of Requirement R3, we point to NERC's initiatives to focus on the biggest risks to reliability of the Bulk Power System (BPS). NERC has developed risk elements to assist each Regional Entity in assessing risk and data submittals are categorized as low risk. We cannot support the revision of R3, as we feel that not only does it meet P81 criteria and there are equally efficient and effective alternatives to the requirement, but also it would be a low risk element that would not be monitored anyway. We urge the standard drafting teams to review requirements under the new approach of risk based compliance monitoring and enforcement to determine if the requirements that are being proposed will mitigate moderate to high risks to the BPS. In this case, R3 will not mitigate moderate or high risks and should be retired.

Response:

The SDT concluded that a standard was necessary. The standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent. Because certain Canadian provinces have adopted only select portions of the NERC Rules of Procedure, a standard is necessary to ensure that NERC and the Regional Entities has the authority to collect the necessary data from all applicable registered entities. The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment.

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Texas RE recommends providing clarity in order to deter entities from activities that do not support reliability.

Response:

Requested area's regional entity, PC or BA should not be requesting any data for any other purposes than reliability. Regional Entity bylaws and delegation agreements are limited to reliability needs. The concerns with other entities requesting data is covered in Requirement R4.

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer:	Yes
Answer Comment:	We would suggest to the drafting team to include in Requirement R3 some alternative language suggesting how to handling 'confidential' information appropriately and its listed as followed: 'The Planning Coordinator or the Balancing Authority shall provide the data collected (public and confidential should be handle appropriately) under Requirement R2 to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties'. Also, we would like the drafting team to add some clarity on whether the data request is applicable to the entities specific Regional Entity or can any Regional Entity request the data from the applicable Planning Coordinator or Balancing Authority?
Response:	We understand your concern and have modified the Background Section to address confidentiality. Concerning confidentiality treatment by a Regional Entity, they are governed by the NERC Rules of Procedure (specifically Section 1500). The SDT has also modified Requirement R3 to address your issue concerning the specific Regional Entity.
Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:	No
Answer Comment:	BPA believes one does not need to give confidential information regarding individual entities when providing details about expected future conditions when looking at the entire electrical system. There may be times when the expected outcome is large enough that individual entities activities can be discerned. Given that planning must be done with confidential information, if clarifying language were provided, BPA suggests that it limits distribution of the data by the receiving entity and does not limit what is communicated - - or in other words, language that indicates all details or communication of the information must be directed to the organization that initiated the document.
Response:	The SDT has modified Requirement R3 to clearly state that an entity has to respond to a request from its Regional Entity regardless of how the data is collected. We understand your concern and have modified the Background Section to address confidentiality. Concerning confidentiality treatment by a Regional Entity, they are governed by the NERC Rules of Procedure (specifically Section 1500). If there are any other known confidentiality issues they should be dealt with prior to the gathering of data since the scope of the data being requested is defined within the approved standard.
Likes:	0
Dislikes:	0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer:	No
Answer Comment:	Requirement 3 has sufficient clarity
Response:	The SDT thanks you for your clarifying comment.
Likes:	0
Dislikes:	0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer:	Yes
Answer Comment:	
Response:	
Likes:	0
Dislikes:	0

2. Do you agree that the standard needs additional clarity regarding the obligations of an applicable entity upon receipt of a data request that seeks confidential information? If not, please explain.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Selected Answer: No

Answer Comment:

Dominion believes that NERC's Rules of Procedure, Section 1500 adequately addresses this.

Response:	Thank you for your clarifying comment.
Likes:	0
Dislikes:	0

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Selected Answer:	Yes
Answer Comment:	*The SRC submits that Requirements R2 and R4 should be revised to provide that the requested data shall be returned to the Applicable Entity subject confidentiality requirements and agreements. This clarification would ensure that entities explore all possible avenues for provision of data that could be deemed confidential prior to exercising its right to refuse provision under Requirement 4.1.*
Response:	The SDT modified Requirement R4 to provide additional clarity regarding confidentiality. The SDT has also added language to the rationale for Requirement R4 to further explain the applicability of confidentiality. We understand your concern and have modified the Background Section to address confidentiality. Concerning confidentiality treatment by a Regional Entity, they are governed by the NERC Rules of Procedure (specifically Section 1500). If there are any other known confidentiality issues they should be dealt with prior to

the gathering of data since the scope of the data being requested is defined within the approved standard.

Likes: 0

Dislikes: 0

Mark Wilson - Independent Electricity System Operator - NA - Not Applicable - NPCC

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: No

Answer Comment:

CPS Energy believes that 4.1 provides the Applicable Entity sufficient rights to refuse to provide the data under 1) failure of the requesting entity to provide a "demonstrated need" for the data or 2) providing the data would confict with the Applicable Entity's confidentiality, regulatory, or security requirements.

Response: Thank you for your clarifying comment.

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the SRC's comments in response to this survey.

Response:

The SDT modified Requirement R4 to provide additional clarity regarding confidentiality. The SDT has also added language to the rationale for Requirement R4 to further explain the applicability of confidentiality.

We understand your concern and have modified the Background Section to address confidentiality. Concerning confidentiality treatment by a Regional Entity, they are governed by the NERC Rules of Procedure (specifically Section 1500). If there are any other known confidentiality issues they should be dealt with prior to the gathering of data since the scope of the data being requested is defined within the approved standard.

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

---

faranak sarbaz - Los Angeles Department of Water and Power - 1 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

MOD-031-1 replaces a number of other MOD standards where the topic of confidential information was not explicitly addressed. AEP believes that MOD-031-1 R4.1 is sufficiently clear as written in regards to the obligations of an applicable entity that receives a request for potentially confidential information.

Response: Thank you for your clarifying comment.

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

In light of our recommendation to remove Requirement R3 from the MOD-031 Reliability Standard (see response to question #1), the emphasis of the standard will primarily be directed at the authority of the Planning Coordinator or Balancing Authority to request demand and energy data from the other applicable entities (Transmission Planner, Resource Planner, Load-Serving Entity, and Distribution Provider) for the purpose of supporting reliability studies and assessments that are performed by the Planning Coordinator or Balancing Authority. If there are no pre-existing agreements that address data confidentiality between the requesting entity (Planning Coordinator or Balancing Authority) and the submitting entity (Transmission Planner, Resource Planner, Load-Serving Entity, and Distribution Provider), we can understand that this may be a cause of concern with the submitting entity (Transmission Planner, Resource Planner, Load-Serving Entity, and Distribution Provider).

Response:

The SDT disagrees with your comment concerning Requirement R3. Please refer to our response to your comment for question #1.

We understand your concern and have modified the Background Section to address confidentiality. Concerning confidentiality treatment by a Regional Entity, they are governed by the NERC Rules of Procedure (specifically Section 1500). If there are any other known confidentiality issues they should be dealt with prior to the gathering of data since the scope of the data being requested is defined within the approved standard.

Likes:	0
Dislikes:	0

Teresa Czyz - Georgia Transmission Corporation - 1 - SERC

Selected Answer:	Yes
Answer Comment:	Again, GTC agrees with the comments provided by ACES Power: We agree additional clarity is needed and recommend removing redundancies in R4. First, R4 should be clarified so that no Resource Planner (RP) can request energy and demand data from another RP. There simply is no situation in which one RP needs another RP's data. This is a FERC standards of conduct issue as it deals with competition between RPs. Second, R4 should not include the PC and BA as requesting entities since they will already be requesting data via R1. These two steps alone will eliminate the majority of the ambiguity and redundancy.
Response:	Information concerning available Generating Resources of the Resource Planner are not included under this standard. If a Resource Planner believes that certain information is confidential, access to that information can be restricted under Requirement R4. The requesting entity's ability to demonstrate a reliability need will determine whether they have right to request the data under Requirement R4. With regards to your comment concerning PCs and BAs being included in Requirement R4, this is referencing "other" PCs and BAs not your PC/BA.

Likes:	0
Dislikes:	0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:	Yes
Answer Comment:	I agree that confidential information disclosures require clarity in light of corporate customer data protection policies and the potential impact resolution of a policy compliant response has on the information request time requirements identified in the MOD. However, with requests at system level, conflicts occurences would be an infrequent exception.
Response:	If there are known confidentiality issues they should be dealt with prior to the gathering of data since the scope of the data being requested is defined within the approved standard.
Likes:	0
Dislikes:	0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Selected Answer:	Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Michael Lowman - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Duke Energy agrees that clarification is needed.

Response:

The SDT modified Requirement R4 to provide additional clarity regarding confidentiality. The SDT has also added language to the rationale for Requirement R4 to further explain the applicability of confidentiality.

We understand your concern and have modified the Background Section to address confidentiality. Concerning confidentiality treatment by a Regional Entity, they are governed by the NERC Rules of Procedure (specifically Section 1500). If there are any other known confidentiality issues they should be dealt with prior to the gathering of data since the scope of the data being requested is defined within the approved standard.

Likes:	0
Dislikes:	0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Selected Answer:	Yes
Answer Comment:	We agree additional clarity is needed and recommend removing redundancies in R4. First, R4 should be clarified so that no Resource Planner (RP) can request energy and demand data from another RP. There simply is no situation in which one RP needs another RP's data. This is a FERC standards of conduct issue as it deals with competition between RPs. Second, R4 should not include the PC and BA as requesting entities since they will already be requesting data via R1. These two steps alone will eliminate the majority of the ambiguity and redundancy.
Response:	Information concerning available Generating Resources of the Resource Planner are not included under this standard. If a Resource Planner believes that certain information is confidential, access to that information can be restricted under Requirement R4. The requesting entity's ability to demonstrate a reliability need will determine whether they have right to request the data under Requirement R4. With regards to your comment concerning PCs and BAs being included in Requirement R4, this is referencing "other" PCs and BAs not your PC/BA.

Likes:	0
Dislikes:	0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:	Yes
Answer Comment:	Texas RE recommends providing clarity in order to deter entities from activities that do not support reliability.
Response:	Requested area's regional entity, PC or BA should not be requesting any data for any other purposes than reliability. Regional Entity bylaws and delegation agreements are limited to reliability needs. The concerns with other entities requesting data is covered in Requirement R4.
Likes:	0
Dislikes:	0

Chris Scanlon - Exelon - 1 -

Selected Answer:	No

Answer Comment:

Exelon doesn't think the requirement needs clarification.

Response: Thank you for your clarifying comment.

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Selected Answer: Yes

Answer Comment:

We agree there should be some type of clarity added to the standard in reference to confidential information. At this point, the current language doesn't suggest the proper handling of confidential information by any of the applicable entities. We would suggest addressing the confidential piece in Requirement R2 where the applicable entities are requesting this type of data should verify potential confidential information and the entity providing this data marking the information as such 'confidential' so there is no confusion on how this data should be handled. We also suggest to the drafting team to mention in the requirement that the data being requested is pertaining to EIA-411 and this connection needs to be re-establish on what type of data is being requested.

Response: We understand your concern and have modified the Background Section to address confidentiality. Concerning confidentiality treatment by a Regional Entity,

they are governed by the NERC Rules of Procedure (specifically Section 1500). If there are any other known confidentiality issues they should be dealt with prior to the gathering of data since the scope of the data being requested is defined within the approved standard. The standard is not meant to detail the handling of confidential information.

With regards to your comment concerning EIA-411, the SDT does not want to put specifics of this type into the standard.

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

BPA believes to properly plan you must provide some confidential information generically.

Response: Thank you for your clarifying comment.

Likes: 0

Dislikes: 0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer: No

Answer Comment:

No additional clarity is needed.

Response: Thank you for your clarifying comment.

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Response:

Likes: 0

Dislikes: 0

Standard Development Timeline

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

Description of Current Draft

This is the first posting of the proposed revised standard. This proposed draft standard will be posted for a 45-day comment period and 10-day initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	April 15, 2015
SAR posted for a 30-day informal comment period	April 16, 2015

Anticipated Actions	Date
45-day formal comment period with initial ballot	August/September 2015
Final ballot	October 2015
NERC Board adoption	November 2015

New or Modified Terms 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.

Term: None

A. Introduction

1. Title: Demand and Energy Data

2. Number: MOD-031-2

3. Purpose: To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. Applicability:

4.1. Functional Entities:

4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "Planning Coordinator")

This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both "Planning Authority" and "Planning Coordinator."

4.1.2 Transmission Planner

4.1.3 Balancing Authority

4.1.4 Resource Planner

4.1.5 Load-Serving Entity

4.1.6 Distribution Provider

5. Effective Date

5.1. See the MOD-031-2 Implementation Plan.

6. Background:

To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, authority is needed to collect the applicable data.

The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management

performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

Data provided under this standard is generally considered confidential by Planning Coordinators and Balancing Authorities receiving the data. Furthermore, data reported to a Regional Entity is subject to the confidentiality provisions in Section 1500 of the North American Electric Reliability Corporation Rules of Procedure and is typically aggregated with data of other functional entities in a non-attributable manner. While this standard allows for the sharing of data necessary to perform certain reliability studies and assessments, any data received under this standard for which an applicable entity has made a claim of confidentiality should be maintained as confidential by the receiving entity.

B. Requirements and Measures

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any,

activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary,:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data listed under Requirement R1 Parts 1.3 through 1.5 for their area to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authority, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

Rationale for R4: This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

The obligation to share data under Requiement R4 does not supersede or otherwise modify any of the Applicable Entity's existing confidentiality obligations. For instance, if an entity is prohibited from providing any of the requested data pursuant to confidentiality provisions of an Open Access Transmission Tariff or a contractual arrangement, Requirement R4 does not require the Applicable Entity to provide the data to a requesting entity. Rather, under Part 4.1, the Applicable Entity must simply provide written notification to the requesting entity that it will not be providing the data and the basis for not providing the data. If the Applicable Entity is subject to confidentiality obligations that allow the Applicable Entity to share the data only if certain conditions are met, the Applicable Entity shall ensure that those conditions are met within the 45-day time period provided in Requirement R4, communicate with the requesting entity regarding an extension of the 45-day time period so as to meet all those conditions, or provide justification under Part 4.1 as to why those conditions cannot be met under the circumstances.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or

otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; and
- shall not be required to provide any requested data that, if provided, would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements; and
- shall not be required to alter the format in which it maintains or uses the data.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, 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.

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 Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.4.1 through part 1.4.5

			did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data collected under Requirement R2 prior to 91

			did so after 75 days from the date of request but prior to 81 days from the date of the request.	did so after 80 days from the date of request but prior to 86 days from the date of the request.	did so after 85 days from the date of request but prior to 91 days from the date of the request.	days or more from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 6, 2014	Adopted by the NERC Board of Trustees.	
1	February 19, 2015	FERC order approving MOD-031-1	

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 R1:

Rationale for R1: To ensure that when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they identify the entities that must provide the data (Applicable Entity in part 1.1), the data to be provided (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions (e.g., temperature, humidity or wind speed), or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

Balancing Authorities are included here to reflect a practice in the WECC Region where BAs are the entity that perform this requirement in lieu of the PC.

Rationale for R2:

This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

Rationale for R3:

This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

Rationale for R4:

This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

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.

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This is the first posting of the proposed revised standard. This proposed draft standard will be posted for a 45-day comment period and 10-day initial ballot.

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NERC Board adoption	November 2015

New or Modified Terms 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.

Term: None

A. Introduction

1. Title: Demand and Energy Data

2. Number: MOD-031-21

3. Purpose: To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. Applicability:

4.1. Functional Entities:

4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "Planning Coordinator")

This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both "Planning Authority" and "Planning Coordinator."

4.1.2 Transmission Planner

4.1.3 Balancing Authority

4.1.4 Resource Planner

4.1.5 Load-Serving Entity

4.1.6 Distribution Provider

5. Effective Date

5.1. See the MOD-031-2 Implementation Plan.~~MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 that is twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

6. Background:

To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, authority is needed to collect the applicable data.

The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning

Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

Data provided under this standard is generally considered confidential by Planning Coordinators and Balancing Authorities receiving the data. Furthermore, data reported to a Regional Entity is subject to the confidentiality provisions in Section 1500 of the North American Electric Reliability Corporation Rules of Procedure and is typically aggregated with data of other functional entities in a non-attributable manner. While this standard allows for the sharing of data necessary to perform certain reliability studies and assessments, any data received under this standard for which an applicable entity has made a claim of confidentiality should be maintained as confidential by the receiving entity.

B. Requirements and Measures

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any, activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary,:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations

(e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data listed~~collected~~ under Requirement R1 Parts 1.3 through 1.5 for their area~~R2~~ to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authority, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

Rationale for R4: This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

The obligation to share data under Requiement R4 does not supersede or otherwise modify any of the Applicable Entity's existing confidentiality obligations. For instance, if an entity is prohibited from providing any of the requested data pursuant to confidentiality provisions of an Open Access Transmission Tariff or a contractual arrangement, Requirement R4 does not require the Applicable Entity to provide the data to a requesting entity. Rather, under Part 4.1, the Applicable Entity must simply provide written notification to the requesting entity that it will not be providing the data and the basis for not providing the data. If the Applicable Entity is subject to confidentiality obligations that allow the Applicable Entity to share the data only if certain conditions are met, the Applicable Entity shall ensure that those conditions are met within the 45-day time period provided in Requirement R4, communicate with the requesting entity regarding an extension of the 45-day time period so as to meet all those conditions, or provide justification under Part 4.1 as to why those conditions cannot be met under the circumstances.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; and
- shall not be required to provide any requested data that, if provided, would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements; and
- shall not be required to alter the format in which it maintains or uses the data.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, 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.

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 Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.4.1 through part 1.4.5

			did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data collected under Requirement R2 prior to 91

			did so after 75 days from the date of request but prior to 81 days from the date of the request.	did so after 80 days from the date of request but prior to 86 days from the date of the request.	did so after 85 days from the date of request but prior to 91 days from the date of the request.	days or more from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 6, 2014	Adopted by the NERC Board of Trustees.	
1	February 19, 2015	FERC order approving MOD-031-1	

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 R1:

Rationale for R1: To ensure that when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they identify the entities that must provide the data (Applicable Entity in part 1.1), the data to be provided (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions (e.g., temperature, humidity or wind speed), or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

Balancing Authorities are included here to reflect a practice in the WECC Region where BAs are the entity that perform this requirement in lieu of the PC.

Rationale for R2:

This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

Rationale for R3:

This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

Rationale for R4:

This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

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Implementation Plan

Project 2010-04.1 Demand and Energy Data

Implementation Plan for MOD-031-2 – Demand and Energy Data

Approvals Required

MOD-031-2 – Demand and Energy Data

Prerequisite Approvals

There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

N/A

Applicable Entities

Planning Coordinator and Planning Authority

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

MOD-031-2 shall become effective as follows:

The later of the effective date of MOD-031-1 or the first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities 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 later of the effective date of MOD-031-1 or the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification

The six-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements

MOD-031-1 shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-2 in the particular jurisdiction in which the new standard is becoming effective.

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Unofficial Comment Form

Project 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the proposed standard **MOD-031-2 – Demand and Energy Data** to address FERC Order No. 804 directives. Comments must be submitted by **8 p.m. Eastern, Friday, September 18, 2015**.

Documents and information about this project are available on the project page. If you have questions, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

Background Information

The collection of demand projections requires coordination and collaboration between Planning Authorities (also referred to as "Planning Coordinators"), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will enhance the reliability of the BPS. Collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. This project will modify the language in Requirement R3 to clarify certain obligations to provide data to the Regional Entity and will also address the directive to consider the compliance obligations of an applicable entity upon receipt of a data request that seeks confidential information.

Questions

1. The SDT has modified MOD-031-1 Requirements R3 and R4 to provide clarity regarding certain obligations to provide data to the Regional Entity and the obligations of an applicable entity upon receipt of a data request seeking confidential information. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain below and provide a proposed solution.

   Yes:

   No:

   Comments:

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Standards Announcement Reminder

Project 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2

Initial Ballot and Non-binding Poll Open through September 18, 2015

Now Available

An initial ballot for draft one of **MOD-031-2 – Demand and Energy Data** and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern, Friday, September 18, 2015.**

Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standard and associated VRFs and VSLs by clicking here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at EROhelpdesk@nerc.net (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process

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

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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Standards Announcement

Project 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2

Formal Comment Period Open through September 18, 2015
Ballot Pools Forming through August 31, 2015

Now Available

A 45-day formal comment period for draft one of **MOD-031-2 – Demand and Energy Data** is open through **8 p.m. Eastern, Friday, September 18, 2015.**

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Monday, August 31, 2015**. Registered Ballot Body members may join the ballot pools here.

Next Steps

An initial ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 9-18, 2015.**

Standards Development Process

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

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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Standards Announcement

Project 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2

RSAW Posted for Industry Comment through Friday, September 18, 2015

Now Available

The draft RSAW for **MOD-031-2 – Demand and Energy Data** is posted on the project page for industry comment through **8 p.m. Eastern, Friday, September 18, 2015**. Submit feedback regarding the draft RSAW to RSAWfeedback@nerc.net**.**

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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Standards Announcement

Project 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2

Initial Ballot and Non-binding Poll Results

Now Available

A formal comment period and initial ballot for draft one of **MOD-031-2 – Demand and Energy Data** as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded **8 p.m. Eastern, Friday, September 18, 2015.**

The initial ballot received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides detailed results for the ballot and non-binding poll.

Ballot	Non-binding Poll
Quorum /Approval	Quorum/Supportive Opinions
85.57% / 87.36%	82.90% / 89.20%

Next Steps

The drafting team will consider all comments received during the formal comment period and determine the next steps for the project.

Standards Development Process

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

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/28)
Ballot Name: 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2 IN 1 ST
Voting Start Date: 9/9/2015 12:01:00 AM
Voting End Date: 9/18/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 255
Total Ballot Pool: 298
Quorum: 85.57
Weighted Segment Value: 87.36

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	76	1	53	0.914	5	0.086	0	9	9
Segment: 2	9	0.6	5	0.5	1	0.1	0	1	2
Segment: 3	68	1	47	0.87	7	0.13	0	4	10
Segment: 4	26	1	15	0.714	6	0.286	0	1	4
Segment: 5	67	1	45	0.938	3	0.062	0	4	15
Segment: 6	41	1	33	0.917	3	0.083	0	2	3
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0.1	1	0.1	0	0	0	0	0
Segment:	2	0.2	1	0.1	1	0.1	0	0	0

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9									
Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	298	6.7	208	5.853	26	0.847	0	21	43

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A

1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Alan MacNaughton		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A

1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Abstain	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A

1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		Affirmative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A

2	Electric Reliability Council of Texas, Inc.	christina bigelow		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		None	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A

3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Third-Party Comments
3	City of Leesburg	Chris Adkins		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Charles Morgan		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	Third-Party Comments
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Grand River Dam Authority	Jeff Wells		Abstain	N/A

3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Mace Hunter		Negative	Third-Party Comments
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	PHI - Potomac	Mark Yerger		Affirmative	N/A

	Electric Power Co.				
3	PNM Resources	Michael Mertz		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa	Ronald Donahey		None	N/A

	Electric Co.				
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila		Negative	Third-Party Comments
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Negative	Third-Party Comments
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Third-Party Comments
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Negative	Comments Submitted
4	Keys Energy	Stanley Rzad		Negative	Third-Party

	Services				Comments
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Municipal Energy Agency of Nebraska	Robin Spady		Abstain	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A

5	Avista - Avista Corporation	Steve Wenke		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		None	N/A
5	BC Hydro and Power Authority	Clement Ma		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Calpine Corporation	Hamid Zakery		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A

5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	David Schumann		Negative	Third-Party Comments
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Abstain	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A

5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Bernard Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A

5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A

6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc	Richard Hoag	Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Third-Party Comments
6	Florida Municipal Power Pool	Tom Reedy		Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
6	Platte River Power	Carol Ballantine		Affirmative	N/A

	Authority				
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		Abstain	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham	Chris Janick	Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Tiffany Lake		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Negative	Third-Party Comments
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability	Peter Heidrich		Affirmative	N/A

	Coordinating Council				
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Joe Spencer		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 298 of 298 entries

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/28)
Ballot Name: 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2 Non-binding Poll IN 1 NB
Voting Start Date: 9/9/2015 12:01:00 AM
Voting End Date: 9/18/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 223
Total Ballot Pool: 269
Quorum: 82.9
Weighted Segment Value: 89.2

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	69	1	42	0.933	3	0.067	0	14	10
Segment: 2	8	0.5	4	0.4	1	0.1	0	1	2
Segment: 3	65	1	37	0.881	5	0.119	0	12	11
Segment: 4	21	1	11	0.688	5	0.312	0	3	2
Segment: 5	60	1	31	0.939	2	0.061	0	10	17
Segment: 6	36	1	25	0.926	2	0.074	0	5	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0.1	1	0.1	0	0	0	0	0
Segment:	2	0.2	1	0.1	1	0.1	0	0	0

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9									
Segment: 10	7	0.5	5	0.5	0	0	0	2	0
Totals:	269	6.3	157	5.467	19	0.833	0	47	46

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric	Tony Kroskey		None	N/A

	Power Cooperative, Inc.				
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A

1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A

1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		None	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Abstain	N/A
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Abstain	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company -	Robert A. Schaffeld		Affirmative	N/A

	Southern Company Services, Inc.				
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		Affirmative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	christina bigelow		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A

2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		None	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Comments Submitted
3	City of Leesburg	Chris Adkins		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs	Charles Morgan		Affirmative	N/A

	Utilities				
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Grand River Dam Authority	Jeff Wells		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Mace Hunter		Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water	Mike Anctil		Affirmative	N/A

	and Power				
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Abstain	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A

3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila		Negative	Comments Submitted
4	City of New Smyrna	Tim Beyrle		Negative	Comments

	Beach Utilities Commission				Submitted
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Negative	Comments Submitted
4	Municipal Energy Agency of Nebraska	Robin Spady		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A

5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Steve Wenke		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		None	N/A
5	BC Hydro and Power Authority	Clement Ma		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Calpine Corporation	Hamid Zakery		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A

5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Abstain	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A

5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Bernard Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	SCANA - South	Edward Magic		None	N/A

	Carolina Electric and Gas Co.				
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		None	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc	Richard Hoag	Affirmative	N/A

6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy		Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		None	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham	Chris Janick	Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A

6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Tiffany Lake		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Joe Spencer		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 269 of 269 entries

Previous 1 Next

Survey Report

Survey Details

Name 2010-04.1 MOD-031 FERC Order No. 804 Directives | MOD-031-2

Description

Start Date 7/31/2015

End Date 9/18/2015

Associated Ballots

2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2 IN 1 ST

2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2 Non-binding Poll IN 1 NB

Survey Questions

1. The SDT has modified MOD-031-1 Requirements R3 and R4 to provide clarity regarding certain obligations to provide data to the Regional Entity and the obligations of an applicable entity upon receipt of a data request seeking confidential information. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain below and provide a proposed solution.

Yes

No

Responses By Question

1. The SDT has modified MOD-031-1 Requirements R3 and R4 to provide clarity regarding certain obligations to provide data to the Regional Entity and the obligations of an applicable entity upon receipt of a data request seeking confidential information. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain below and provide a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Group Information

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2
Kathleen Goodman	ISONE	NPCC	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2

Voter Information

Voter

Albert DiCaprio

Segment

2

Entity

PJM Interconnection, L.L.C.

Region(s)

RFC

Selected Answer: Yes

Answer Comment: The ISO/RTO Standards Review Committee (ERCOT abtaining) agrees with the proposed revisions.

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

While the revisions provide clarity about the provision of data, they create ambiguity regarding how a BA or RC as the responsible entity responds to a data request for data that they do not and have not collected under related requirements in MOD-031. More specifically, Requirement R3 requires a BA or PC to provide data listed in Requirements R1.3 through R1.5 in response to a request by a Regional Entity; however, it does not consider that such entity might not collect all listed data. Accordingly, Requirement R3 could be read to require an entity to collect such data (whether they need to do so or not) solely for the purposes of responding to a Regional Entity request, which activity would be administratively burdensome and would provide no benefit to reliability - especially considering that the Regional Entity could directly request data not collected by a BA or PC from those entities from whom the BA or PC would be required to collect the data.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment: Please refer to ERCOT's responses provided in response to the MOD-031-1 survey.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: No

Answer Comment:

Given the stongly suppported rationale for deactivating the LSE registration function under the Risk-Based Registration initiative, Requirement 2 and Requirement 4 should be revised to remove the reference to LSE.

Document Name:

Likes: 0

Dislikes: 0

Teresa Czyz - Teresa Czyz - -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: Yes

Answer Comment:

The NSRF recommends that R4 bulleted items be updated to reflect the below changes. Our biggest concern is that all three bulleted items must be accomplished since there is an “and” at the end of the first and second bullet. The new wording allows entities the flexibility, which the NSRF believes is the intent of the bulleted items. The NSRF recommends:

- Shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement, unless,
- The requested data, if provided, would conflict with Applicable Entity’s confidentiality, regulatory, or security requirements
- Shall not be required to alter the format in which it maintains or uses the data.

Document Name:

Likes: 0

Dislikes: 0

Tom Reedy - Florida Municipal Power Pool - 6 -

Selected Answer: No

Answer Comment:

While the revisions provide clarity about the provision of data, they create ambiguity regarding how a BA or RC as the responsible entity responds to a data request for data that they do not and have not collected under related requirements in MOD-031. More specifically, Requirement R3 requires a BA or PC to provide data listed in Requirements R1.3 through R1.5 in response to a request by a Regional Entity; however, it does not consider that such entity might not collect all listed data. Accordingly, Requirement R3 could be read to require an entity to collect such data (whether they need to do so or not) solely for the purposes of responding to a Regional Entity request, which activity would be administratively burdensome and would provide no benefit to reliability - especially considering that the Regional Entity could directly request data not collected by a BA or PC from those entities from whom the BA or PC would be required to collect the data.

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Elizabeth Axson On Behalf of: christina bigelow, Electric Reliability Council of Texas, Inc., 2

Selected Answer:

Answer Comment:

While the revisions provide clarity about the provision of data, they create ambiguity regarding how a BA or RC as the responsible entity responds to a data request for data that they do not and have not collected under related requirements in MOD-031. More specifically, Requirement R3 requires a BA or PC to provide data listed in Requirements R1.3 through R1.5 in response to a request by a Regional Entity; however, it does not consider that such entity might not collect all listed data. Accordingly, Requirement R3 could be read to require an entity to collect such data (whether they need to do so or not) solely for the purposes of responding to a Regional Entity request, which activity would be administratively burdensome and would provide no benefit to reliability - especially considering that the Regional Entity could directly request data not

collected by a BA or PC from those entities from whom the BA or PC would be required to collect the data.

Christina Bigelow, Electric Reliability Council of Texas, Inc., 2, 8/31/2015

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Group Information

Group Name: NCP and Nash

Group Member Name	Entity	Region	Segments
Louis Slade	Dominion - NERC Compliance Policy	NA - Not Applicable	1,3,5,6
Randi Heise	Dominion - NERC Compliance Policy	NA - Not Applicable	1,3,5,6
Larry Nash	Dominion - Electric Transmission Compliance	SERC	1,3,5,6

Voter Information

Voter

Connie Lowe

Segment

3

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: Yes

Answer Comment: Given that NERC has requested removal of LSE (docket # RR15-4-000) from NERC Registry Criteria, Dominion suggests removal in this standard.

Document Name:

Likes: 0

Dislikes: 0

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NA - Not Applicable

Selected Answer: Yes

Answer Comment:

Additional comments :

- Hydro-Québec TransÉnergie's Compliance staff recently questioned a TP, BA, LSE and an entity from a neighbouring Interconnection on how to calculate Integrated demands (see 1.3.1 and 1.3.2 of MOD-031) and received 4 different answers. We recommend adding these terms to the NERC glossary with a mathematical formula or adding the formulae to an Appendix of MOD-031.

- Requested change to Implementation Plan:

Considering the nature of proposed changes to MOD-031 e.g. ensuring that the obligation to share data under Requirement R4 does not supersede or otherwise modify any of the Applicable Entity's existing confidentiality obligations, we believe that version 2 does not require any delay for implementation and is easier to implement than version 1. Therefore, we suggest that the implementation calendar be modified to read:

"MOD -031- 2 shall become effective as

The later of the effective date of MOD 31 -
quarter after the date that this standard is approved by applicable regulatory authorities 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 later of the effective date of MOD -
or the first day of the first calendar quarter after the date the standard is adopted bythe NERC Board of Trustees or as otherwise provided for in that jurisdiction."

Document Name:

Likes: 0

Dislikes: 0

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-04.1 MOD-031 FERC Order No. 804 Directives - MOD-031-2

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5

Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: Yes

Answer Comment: Requirement is spelled incorrectly in the opening sentence of the second paragraph in the Rationale for R4.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - SPP - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Timothy Owens	Nebraska Public Power District	MRO	1,3,5
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Mahmood Safi	Omaha Public Power District	MRO	1,3,5
Jonathan Hayes	Southwest Power Pool	SPP	2
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter

Jason Smith

Segment

2

Entity

SPP

Region(s)

SPP

Selected Answer: Yes

Answer Comment:

We disagree with the proposed change to strike the word “collected” and change it to “listed” in R3. The data in R1.3 – R1.5 is allowed to be determined to be collected by Planning Coordinator and Balancing Authority “as necessary” per R1. By changing the word in Requirement R3 to “listed”, the data is inferred to be ‘forced to be collected’ since it is in the R1.3-1.5 list rather than determined to be ‘necessary to be collected’.

We would also suggest removing the term ‘Load-Serving Entity’ from the applicability section of the requirement.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Duke Energy agrees with the proposed changes, and thanks the drafting team for their efforts.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Texas RE noticed the VSLs for R3 references R2, rather than the requirement language which references “R1 Parts 1.3 through 1.5”.

Texas RE is concerned the terms listed under R4, “confidentiality, regulatory, or security requirements”, are vague. This language allows a registered entity to fail to respond to a data request by citing any source of confidentiality, regulatory, or security requirements, regardless of its legitimacy or importance. Texas RE request that the SDT provide examples of confidentiality provisions of an Open Access Transmission Tariff or a contractual arrangement that would prevent an Applicable Entity from providing data included in parts 1.3 -1.5 R1.

Document Name:

Likes: 0

Dislikes: 0

Michiko Sell - Public Utility District No. 2 of Grant County, Washington - 1 -

Selected Answer: Yes

Answer Comment:

However, the use of "Applicable Entity" throughout the Standard is problematic as it is not a NERC defined term.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. suggests that the wording “applicable entity in its area” (R1), and “applicable Regional Entity” (R3) be revised to add more clarity. The current wording is also ambiguous in specifying what data is required, and the requirement may be left open to any requests for data collection. For clarity, the standard should also specify minimum requirements. Further, the standard’s applicability to Load Serving Entities should be removed, given NERC’s intention to remove this functional entity from its list of available functional registrations.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: Yes

Answer Comment:

We appreciate the SDT’s efforts on clarifying the obligations to provide data to Regional Entities and the obligations of an applicable entity upon receipt of a data request seeking confidential information. We agree the proposed modifications provide sufficient clarity.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2010-04.1 MOD-031 FERC Order No. 804 Directives | MOD-031-2

Comment Period Start Date: 7/31/2015

Comment Period End Date: 9/18/2015

Associated Ballot: 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2 IN 1 ST

There were 28 responses, including comments from approximately 93 different people from approximately 64 different companies representing 9 of the 10 Industry Segments as shown on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. **The SDT has modified MOD-031-1 Requirements R3 and R4 to provide clarity regarding certain obligations to provide data to the Regional Entity and the obligations of an applicable entity upon receipt of a data request seeking confidential information. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain below and provide a proposed solution.**

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

1. The SDT has modified MOD-031-1 Requirements R3 and R4 to provide clarity regarding certain obligations to provide data to the Regional Entity and the obligations of an applicable entity upon receipt of a data request seeking confidential information. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain below and provide a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2
Kathleen Goodman	ISONE	NPCC	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2

Selected Answer:	Yes
Answer Comment:	The ISO/RTO Standards Review Committee (ERCOT abtaining) agrees with the proposed revisions. Thank you for your affirmative response.

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:	No
Answer Comment:	While the revisions provide clarity about the provision of data, they create ambiguity regarding how a BA or RC as the responsible entity responds to a data request for data that they do not and have not collected under related requirements in MOD-031. More specifically, Requirement R3 requires a BA or PC to provide data listed in Requirements R1.3 through R1.5 in response to a request by a Regional Entity; however, it does not consider that such entity might not collect all listed data. Accordingly, Requirement R3 could be read to require an entity to collect such data (whether they need to do so or not) solely for the purposes of responding to a Regional Entity request, which activity would be administratively burdensome and would provide no benefit to reliability - especially considering that the Regional Entity could directly request data not collected by a BA or PC from those entities from whom the BA or PC would be required to collect the data.

	The data specific to this standard is for the collection and reporting of data necessary for reliability analysis. The scope of the data is consistent with the current MOD standards that will be replaced by this standard. The SDT believes that if the entity does not have the data requested the entity would be required to collect the data and provide such data to the Regional Entity under this requirement.
Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1	
Selected Answer:	Yes
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Selected Answer:	Yes
Leonard Kula - Independent Electricity System Operator - 2 -	
Selected Answer:	Yes
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Selected Answer:	Yes
christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -	

Selected Answer:	No
Answer Comment:	Please refer to ERCOT's responses provided in response to the MOD-031-1 survey. Please see our response to ERCOT's comments.

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:	No
Answer Comment:	Given the stongly suppported rationale for deactivating the LSE registration function under the Risk-Based Registration initiative, Requirement 2 and Requirement 4 should be revised to remove the reference to LSE. The deactivation of the LSE registration is not final at this point in time. When and if the deactivation occurs all standards that are applicable to an LSE will be re-evaluated.

Teresa Czyz - Teresa Czyz - -

Selected Answer:	Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2

Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

Answer Comment: The NSRF recommends that R4 bulleted items be updated to reflect the below changes. Our biggest concern is that all three bulleted items must be accomplished since there is an "and" at the end of the first and second bullet. The new wording allows entities the flexibility, which the NSRF believes is the intent of the bulleted items. The NSRF recommends:

- Shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement, unless,
- The requested data, if provided, would conflict with Applicable Entity's confidentiality, regulatory, or security requirements
- Shall not be required to alter the format in which it maintains or uses the data.

The SDT modified the requirement to address your concerns.

Tom Reedy - Florida Municipal Power Pool - 6 -

Selected Answer:	No
Answer Comment:	While the revisions provide clarity about the provision of data, they create ambiguity regarding how a BA or RC as the responsible entity responds to a data request for data that they do not and have not collected under related requirements in MOD-031. More specifically, Requirement R3 requires a BA or PC to provide data listed in Requirements R1.3 through R1.5 in response to a request by a Regional Entity; however, it does not consider that such entity might not collect all listed data. Accordingly, Requirement R3 could be read to require an entity to collect such data (whether they need to do so or not) solely for the purposes of responding to a Regional Entity request, which activity would be administratively burdensome and would provide no benefit to reliability - especially considering that the Regional Entity could directly request data not collected by a BA or PC from those entities from whom the BA or PC would be required to collect the data. The data specific to this standard is for the collection and reporting of data necessary for reliability analysis. The scope of the data is consistent with the current MOD standards that will be replaced by this standard. The SDT believes that if the entity does not have the data requested the entity would be required to collect the data and provide such data to the Regional Entity under this requirement.

Elizabeth Axson - Elizabeth Axson On Behalf of: christina bigelow, Electric Reliability Council of Texas, Inc., 2

Selected Answer:

Answer Comment:

While the revisions provide clarity about the provision of data, they create ambiguity regarding how a BA or RC as the responsible entity responds to a data request for data that they do not and have not collected under related requirements in MOD-031. More specifically, Requirement R3 requires a BA or PC to provide data listed in Requirements R1.3 through R1.5 in response to a request by a Regional Entity; however, it does not consider that such entity might not collect all listed data. Accordingly, Requirement R3 could be read to require an entity to collect such data (whether they need to do so or not) solely for the purposes of responding to a Regional Entity request, which activity would be administratively burdensome and would provide no benefit to reliability - especially considering that the Regional Entity could directly request data not collected by a BA or PC from those entities from whom the BA or PC would be required to collect the data.

The data specific to this standard is for the collection and reporting of data necessary for reliability analysis. The scope of the data is consistent with the current MOD standards that will be replaced by this standard. The SDT believes that if the entity does not have the data requested the entity would be required to collect the data and provide such data to the

Regional Entity under this requirement.

Christina Bigelow, Electric Reliability Council of Texas, Inc., 2, 8/31/2015

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Group Name: NCP and Nash

Group Member Name	Entity	Region	Segments
Louis Slade	Dominion - NERC Compliance Policy	NA - Not Applicable	1,3,5,6
Randi Heise	Dominion - NERC Compliance Policy	NA - Not Applicable	1,3,5,6
Larry Nash	Dominion - Electric Transmission Compliance	SERC	1,3,5,6

Selected Answer:	Yes
Answer Comment:	Given that NERC has requested removal of LSE (docket # RR15-4-000) from NERC Registry Criteria, Dominion suggests removal in this standard. The deactivation of the LSE registration is not final at this point in time. When and if the deactivation occurs all standards that are applicable to an LSE will be re-evaluated.

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NA - Not Applicable

Selected Answer:	Yes
Answer Comment:	Additional comments : • Hydro-Québec TransÉnergie's Compliance staff recently questioned a TP, BA, LSE and an entity from a neighbouring Interconnection on how to calculate Integrated demands (see 1.3.1 and 1.3.2 of MOD-031) and received 4 different answers. We recommend adding these terms to the NERC glossary with a mathematical formula or adding the formulae to an Appendix of MOD-031. The SDT believes that your suggested modification is outside the scope of the SAR created for development of this draft of the standard. The SDT encourages you to develop a SAR to address your issue and submit it to NERC. • Requested change to Implementation Plan:

Considering the nature of proposed changes to MOD-031 e.g. ensuring that the obligation to share data under Requirement R4 does not supersede or otherwise modify any of the Applicable Entity's existing confidentiality obligations, we believe that version 2 does not require any delay for implementation and is easier to implement than version 1. Therefore, we suggest that the implementation calendar be modified to read:

"MOD-031-2 shall become effective as follows:

The later of the effective date of MOD-031-1 or the first day of the first calendar quarter after the date that this standard is approved by applicable regulatory authorities 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 later of the effective date of MOD-031-1 or the first day of the first calendar quarter after the date the standard is adopted bythe NERC Board of Trustees or as otherwise provided for in that jurisdiction."

The SDT thanks you for your suggested modification to the effective date. However, the SDT does not believe that it has industry consensus to support modifying the effective date.

Bob Solomon - Hoosier Energy Rural Electric Cooperative, Inc. - 1 -

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-04.1 MOD-031 FERC Order No. 804 Directives - MOD-031-2

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8

Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1

Selected Answer: Yes

Answer Comment: Requirement is spelled incorrectly in the opening sentence of the second paragraph in the Rationale for R4.
The SDT thanks you for your affirmative response and suggested correction. The SDT has made the necessary change to the rationale box for Requirement R4.

Jason Smith - SPP - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Timothy Owens	Nebraska Public Power District	MRO	1,3,5
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Mahmood Safi	Omaha Public Power District	MRO	1,3,5
Jonathan Hayes	Southwest Power Pool	SPP	2
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Answer Comment:	We disagree with the proposed change to strike the word "collected" and change it to "listed" in R3. The data in R1.3 – R1.5 is allowed to be determined to be collected by Planning Coordinator and Balancing Authority "as necessary" per R1. By changing the word in Requirement R3 to "listed", the data is inferred to be 'forced to be collected' since it is in the R1.3-1.5 list rather than determined to be 'necessary to be collected'. The early part of the requirement referencing Part 1.3 through Part 1.5 is the possible scope of the request. The request, later in the requirement, provides the actual scope of what an entity must provide. We would also suggest removing the term 'Load-Serving Entity' from the applicability section of the requirement. The deactivation of the LSE registration is not final at this point in time. When and if the deactivation occurs all standards that are applicable to an LSE will be re-evaluated.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1

Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment: **Duke Energy agrees with the proposed changes, and thanks the drafting team for their efforts.**
The SDT thanks you for your affirmative response.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment: Texas RE noticed the VSLs for R3 references R2, rather than the requirement language which references "R1 Parts 1.3 through 1.5".
The SDT has made the correction.

Texas RE is concerned the terms listed under R4, "confidentiality, regulatory, or security requirements", are vague.
Given the myriad of confidentiality, regulatory and security requirements, the standard drafting team determined that it was not appropriate to detail the exact nature of those requirements in the standard. However, under Part 4.1, the entity must provide a written response justifying the refusal to provide requested data. If, in the judgment of an auditor, the

	justification was not legitimate, the entity may have violated the standard. This language allows a registered entity to fail to respond to a data request by citing any source of confidentiality, regulatory, or security requirements, regardless of its legitimacy or importance. Texas RE request that the SDT provide examples of confidentiality provisions of an Open Access Transmission Tariff or a contractual arrangement that would prevent an Applicable Entity from providing data included in parts 1.3-1.5 of Requirement R1. As an example of confidentiality provisions, the SDT points to the EEI response to the FERC NOPR for MOD-031-1.
Michiko Sell - Public Utility District No. 2 of Grant County, Washington - 1 -	
Selected Answer:	Yes
Answer Comment:	However, the use of "Applicable Entity" throughout the Standard is problematic as it is not a NERC defined term. The SDT thanks you for your affirmative response. You are correct that the term Applicable Entity is not defined in the NERC Glossary of Terms but it is defined within this standard in Requirement R1 Part 1.1.
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3	

Selected Answer:	No
Answer Comment:	Hydro One Networks Inc. suggests that the wording "applicable entity in its area" (R1), and "applicable Regional Entity" (R3) be revised to add more clarity. With regards to use of the term "applicable entity", the term is further defined in Requirement R1 Part 1.1. The term "applicable Regional Entity" is referencing the requesting Regional Entity. The current wording is also ambiguous in specifying what data is required, and the requirement may be left open to any requests for data collection. For clarity, the standard should also specify minimum requirements. The data that may be requested under this standard is defined and bounded in Requirement R1. "Any or all" of the data in Requirement R1 Part 1.3 through Part 1.5 may be requested. Relating to the minimum requirement, there is no requirement to collect data if it is not determined to be necessary by the requesting entity. Further, the standard's applicability to Load Serving Entities should be removed, given NERC's intention to remove this functional entity from its list of available functional registrations. The deactivation of the LSE registration is not final at this point in time. When and if the deactivation occurs all standards that are applicable to an LSE will be re-evaluated.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Selected Answer: Yes

Answer Comment:	We appreciate the SDT's efforts on clarifying the obligations to provide data to Regional Entities and the obligations of an applicable entity upon receipt of a data request seeking confidential information. We agree the proposed modifications provide sufficient clarity. The SDT thanks you for your affirmative response.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Selected Answer:	Yes

End of Report

Standard Development Timeline

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

Description of Current Draft

This is the first posting of the proposed revised standard. This proposed draft standard will be posted for a 45-day comment period and 10-day initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	April 15, 2015
SAR posted for a 30-day informal comment period	April 16, 2015

Anticipated Actions	Date
45-day formal comment period with initial ballot	August/September 2015
Final ballot	October 2015
NERC Board adoption	November 2015

New or Modified Terms 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.

Term: None

A. Introduction

1. Title: Demand and Energy Data

2. Number: MOD-031-2

3. Purpose: To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. Applicability:

4.1. Functional Entities:

4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "Planning Coordinator")

This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both "Planning Authority" and "Planning Coordinator."

4.1.2 Transmission Planner

4.1.3 Balancing Authority

4.1.4 Resource Planner

4.1.5 Load-Serving Entity

4.1.6 Distribution Provider

5. Effective Date

5.1. See the MOD-031-2 Implementation Plan.

6. Background:

To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, authority is needed to collect the applicable data.

The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management

performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

Data provided under this standard is generally considered confidential by Planning Coordinators and Balancing Authorities receiving the data. Furthermore, data reported to a Regional Entity is subject to the confidentiality provisions in Section 1500 of the North American Electric Reliability Corporation Rules of Procedure and is typically aggregated with data of other functional entities in a non-attributable manner. While this standard allows for the sharing of data necessary to perform certain reliability studies and assessments, any data received under this standard for which an applicable entity has made a claim of confidentiality should be maintained as confidential by the receiving entity.

B. Requirements and Measures

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any,

activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary,:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data listed under Requirement R1 Parts 1.3 through 1.5 for their area to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authority, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

Rationale for R4: This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

The obligation to share data under Requirement R4 does not supersede or otherwise modify any of the Applicable Entity's existing confidentiality obligations. For instance, if an entity is prohibited from providing any of the requested data pursuant to confidentiality provisions of an Open Access Transmission Tariff or a contractual arrangement, Requirement R4 does not require the Applicable Entity to provide the data to a requesting entity. Rather, under Part 4.1, the Applicable Entity must simply provide written notification to the requesting entity that it will not be providing the data and the basis for not providing the data. If the Applicable Entity is subject to confidentiality obligations that allow the Applicable Entity to share the data only if certain conditions are met, the Applicable Entity shall ensure that those conditions are met within the 45-day time period provided in Requirement R4, communicate with the requesting entity regarding an extension of the 45-day time period so as to meet all those conditions, or provide justification under Part 4.1 as to why those conditions cannot be met under the circumstances.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or

otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall not be required to alter the format in which it maintains or uses the data;
- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; unless providing the requested data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements

4.1. If the Applicable Entity does not provide data requested because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, 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.

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 Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.4.1 through part 1.4.5

			did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data requested, but did so after 75 days	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data requested, but did so after 80 days	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data requested, but did so after 85 days	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data requested prior to 91 days

			from the date of request but prior to 81 days from the date of the request.	from the date of request but prior to 86 days from the date of the request.	from the date of request but prior to 91 days from the date of the request.	or more from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 6, 2014	Adopted by the NERC Board of Trustees.	
1	February 19, 2015	FERC order approving MOD-031-1	

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 R1:

Rationale for R1: To ensure that when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they identify the entities that must provide the data (Applicable Entity in part 1.1), the data to be provided (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions (e.g., temperature, humidity or wind speed), or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

Balancing Authorities are included here to reflect a practice in the WECC Region where BAs are the entity that perform this requirement in lieu of the PC.

Rationale for R2:

This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

Rationale for R3:

This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

Rationale for R4:

This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

Standard Development Timeline

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

Description of Current Draft

This is the first posting of the proposed revised standard. This proposed draft standard will be posted for a 45-day comment period and 10-day initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	April 15, 2015
SAR posted for a 30-day informal comment period	April 16, 2015

Anticipated Actions	Date
45-day formal comment period with initial ballot	August/September 2015
Final ballot	October 2015
NERC Board adoption	November 2015

New or Modified Terms 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.

Term: None

A. Introduction

1. Title: Demand and Energy Data

2. Number: MOD-031-2

3. Purpose: To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. Applicability:

4.1. Functional Entities:

4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "Planning Coordinator")

This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both "Planning Authority" and "Planning Coordinator."

4.1.2 Transmission Planner

4.1.3 Balancing Authority

4.1.4 Resource Planner

4.1.5 Load-Serving Entity

4.1.6 Distribution Provider

5. Effective Date

5.1. See the MOD-031-2 Implementation Plan.

6. Background:

To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, authority is needed to collect the applicable data.

The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management

performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

Data provided under this standard is generally considered confidential by Planning Coordinators and Balancing Authorities receiving the data. Furthermore, data reported to a Regional Entity is subject to the confidentiality provisions in Section 1500 of the North American Electric Reliability Corporation Rules of Procedure and is typically aggregated with data of other functional entities in a non-attributable manner. While this standard allows for the sharing of data necessary to perform certain reliability studies and assessments, any data received under this standard for which an applicable entity has made a claim of confidentiality should be maintained as confidential by the receiving entity.

B. Requirements and Measures

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any,

activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary,:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data listed under Requirement R1 Parts 1.3 through 1.5 for their area to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authority, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

Rationale for R4: This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

The obligation to share data under Requirement R4 does not supersede or otherwise modify any of the Applicable Entity's existing confidentiality obligations. For instance, if an entity is prohibited from providing any of the requested data pursuant to confidentiality provisions of an Open Access Transmission Tariff or a contractual arrangement, Requirement R4 does not require the Applicable Entity to provide the data to a requesting entity. Rather, under Part 4.1, the Applicable Entity must simply provide written notification to the requesting entity that it will not be providing the data and the basis for not providing the data. If the Applicable Entity is subject to confidentiality obligations that allow the Applicable Entity to share the data only if certain conditions are met, the Applicable Entity shall ensure that those conditions are met within the 45-day time period provided in Requirement R4, communicate with the requesting entity regarding an extension of the 45-day time period so as to meet all those conditions, or provide justification under Part 4.1 as to why those conditions cannot be met under the circumstances.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or

otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall not be required to alter the format in which it maintains or uses the data;
- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; ~~and~~unless providing
- ~~shall not be required to provide any~~the requested data ~~that, if provided,~~ would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements~~; and~~
- ~~shall not be required to alter the format in which it maintains or uses the data.~~

4.1. If the Applicable Entity does not provide data requested because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, 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.

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 Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.4.1 through part 1.4.5

			did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data requested~~collected~~	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data requested~~collected~~	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data requested~~collected~~	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data requested~~collected under Requirement R2~~ prior to 91

			~~under Requirement R2~~, but did so after 75 days from the date of request but prior to 81 days from the date of the request.	~~under Requirement R2~~, but did so after 80 days from the date of request but prior to 86 days from the date of the request.	~~under Requirement R2~~, but did so after 85 days from the date of request but prior to 91 days from the date of the request.	days or more from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 6, 2014	Adopted by the NERC Board of Trustees.	
1	February 19, 2015	FERC order approving MOD-031-1	

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 R1:

Rationale for R1: To ensure that when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they identify the entities that must provide the data (Applicable Entity in part 1.1), the data to be provided (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions (e.g., temperature, humidity or wind speed), or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

Balancing Authorities are included here to reflect a practice in the WECC Region where BAs are the entity that perform this requirement in lieu of the PC.

Rationale for R2:

This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

Rationale for R3:

This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

Rationale for R4:

This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

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Implementation Plan

Project 2010-04.1 Demand and Energy Data

Implementation Plan for MOD-031-2 – Demand and Energy Data

Approvals Required

MOD-031-2 – Demand and Energy Data

Prerequisite Approvals

There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

N/A

Applicable Entities

Planning Coordinator and Planning Authority

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

MOD-031-2 shall become effective as follows:

The later of the effective date of MOD-031-1 or the first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities 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 later of the effective date of MOD-031-1 or the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification

The six-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements

MOD-031-1 shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-2 in the particular jurisdiction in which the new standard is becoming effective.

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Standards Announcement

Project 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2

Final Ballot Open through October 15, 2015

Now Available

A final ballot for **MOD-031-2 – Demand and Energy Data** is open through **8 p.m. Eastern, Thursday, October 15, 2015.**

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a vote. All ballot pool members may change their previously cast vote. A ballot pool member who failed to vote during the previous ballot period may vote in the final ballot period. If a ballot pool member does not participate in the final ballot, the member's vote from the previous ballot will be carried over as their vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard here. If you experience any difficulties using the Standards Balloting & Commenting System (SBS), contact Wendy Muller.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at EROhelpdesk@nerc.net (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The voting results for the standard will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

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

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2

Final Ballot Results

Now Available

A final ballot for **MOD-031-2 – Demand and Energy Data** concluded **8 p.m. Eastern, Thursday, October 15, 2015.**

The standard received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides detailed results for the ballot.

Ballot
Quorum / Approval
89.60% / 90.01%

Next Steps

The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

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

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

North American Electric Reliability Corporation
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BALLOT RESULTS

Ballot Name: 2010-04.1 MOD-031 FERC Order No. 804 Directives MOD-031-2 FN 2 ST
Voting Start Date: 10/6/2015 12:17:53 PM
Voting End Date: 10/15/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 267
Total Ballot Pool: 298
Quorum: 89.6
Weighted Segment Value: 90.01

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	76	1	58	0.935	4	0.065	0	7	7
Segment: 2	9	0.9	8	0.8	1	0.1	0	0	0
Segment: 3	68	1	52	0.897	6	0.103	0	3	7
Segment: 4	26	1	16	0.762	5	0.238	0	1	4
Segment: 5	67	1	52	0.963	2	0.037	0	3	10
Segment: 6	41	1	34	0.944	2	0.056	0	2	3
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0.1	1	0.1	0	0	0	0	0
Segment: 9	2	0.2	1	0.1	1	0.1	0	0	0

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Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	298	7	230	6.301	21	0.699	0	16	31

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas		Negative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Abstain	N/A

1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A

1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Alan MacNaughton		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		None	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Affirmative	N/A
1	Northeast Missouri Electric Power	Kevin White		Affirmative	N/A

	Cooperative				
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Abstain	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Negative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A

1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		Affirmative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	New York	Gregory Campoli		Affirmative	N/A

	Independent System Operator				
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	N/A
3	City of Leesburg	Chris Adkins		Negative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs	Charles Morgan		Affirmative	N/A

	Utilities				
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Grand River Dam Authority	Jeff Wells		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		Negative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	Los Angeles Department of Water	Mike Anctil		Affirmative	N/A

	and Power				
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Abstain	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		Affirmative	N/A

3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila		Negative	N/A

4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Negative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Keys Energy Services	Stanley Rzad		Negative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Municipal Energy Agency of Nebraska	Robin Spady		Abstain	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Negative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A

4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Steve Wenke		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		None	N/A
5	BC Hydro and Power Authority	Clement Ma		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Affirmative	N/A
5	Calpine Corporation	Hamid Zakery		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Affirmative	N/A
5	City of Independence, Power and Light	Jim Nail		Affirmative	N/A

	Department				
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Affirmative	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	David Schumann		Negative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric	Kayleigh Wilkerson		Affirmative	N/A

	System				
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		Abstain	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	N/A
5	Oglethorpe Power Corporation	Bernard Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A

5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A

6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc	Richard Hoag	Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy		Negative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and	Ryan Streck		Affirmative	N/A

	Water				
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		Abstain	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham	Chris Janick	Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A

6	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Negative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Exhibit E

Standards Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2010-04.1 Standards Drafting Team
MOD-031-2

	Name	Company	Contact
1	Mark Kuras	PJM	Mark.Kuras@pjm.com
2	Paul Kure	Reliability*First* Corporation (RFC)	paul.kure@rfirst.org
3	Brian Glover	Great River Energy	BGlover@GREnergy.com
4	Robert Emmert	Califiornia ISO (CAISO)	REmmert@caiso.com
5	Barbara Doland	SERC Reliability Corporation, Inc.	BDoland@serc1.org
6	Andrey Oks	Northeast Power Coordinating Council, Inc. (NPCC)	aoks@npcc.org
6	Shamai Elstein	NERC	shamai.elstein@nerc.net
6	Darrel Richardson	NERC	darrel.richardson@nerc.net

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Relay Performance During Stable Swings Reliability Standard	**)** **)**	**Docket No. RM15-8-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

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November 23, 2015

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BEFORE THE
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Relay Performance During Stable Power Swings Reliability Standard	**)** **)**	**Docket No. RM15-8-000**

COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

The North American Electric Reliability Corporation ("NERC")[1] hereby provides these comments in response to the Federal Energy Regulatory Commission's ("FERC" or the "Commission") September 17, 2015, Notice of Proposed Rulemaking ("NOPR")[2] proposing to approve Reliability Standard PRC-026-1 (*Relay Performance During Stable Power Swings*).

I. BACKGROUND

On December 31, 2014, NERC submitted a petition for approval of proposed Reliability Standard PRC-026-1, including the associated implementation plan and proposed Violation Risk Factors and Violation Severity Levels, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The proposed Reliability Standard was submitted in compliance with Order No. 733,[3] in which the Commission directed NERC, pursuant to section 215 (d)(5) of the Federal Power Act, to develop a new Reliability Standard that requires the use

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[1] The Federal Energy Regulatory Commission certified NERC as the Electric Reliability Organization ("ERO") in its order issued on July 20, 2006, in Docket No. RR06-1-000. *N. Am. Elec. Rel. Corp.*, 116 FERC ¶ 61,062 (2006).

[2] *Relay Performance During Stable Power Swings Reliability Standard*, 152 FERC ¶ 61,200 (2015) ("NOPR").

[3] *Transmission Relay Loadability Reliability Standard*, Order No. 733, 130 FERC ¶ 31,221 (2010), *order on reh'g and clarification*, Order No. 733-A, 134 FERC ¶ 61, 127 (2011), *order on reh'g and clarification*, Order No. 733-B, 136 FERC ¶ 61, 185 (2011).

of protective relay systems that can differentiate between faults and stable power swings and, when necessary, retirement of protective relay systems that cannot meet this requirement.[4]

The Commission proposes to approve Reliability Standard PRC-026-1 and states that the Reliability Standard addresses the "directive from Order No. 733 by helping to prevent the unnecessary tripping of bulk electric system elements in response to stable power swings."[5] In the NOPR, the Commission requested comments regarding the potential burden of modifying the applicability of proposed Reliability Standard PRC-026-1 to include relays with a time delay of 15 cycles or greater in instances where either (1) an element has been identified by a Planning Coordinator as potentially susceptible to power swings, or (2) an entity becomes aware of a Bulk Electric System element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s), even if the element was not previously identified by the Planning Coordinator.[6]

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[7]

4 Order No. 733, 130 ¶ FERC 61, 221 at P 150.
5 NOPR at P 13.
6 *Id.* at P 2.
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 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

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III. COMMENTS

NERC supports the Commission's proposal to approve Reliability Standard PRC-026-1 as submitted. The standard is applicable to the Planning Coordinator; and Generator Owner and Transmission Owner that apply load-responsive protective relays on generators, transformers, and transmission lines. Load-responsive protective relays that are set to trip instantaneously (i.e., without intentional time-delay) are at greatest risk to power swings and are those relays that PRC-026-1 fundamentally addresses. The proposed standard includes in its applicability section load-responsive protective relays which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to: phase distance, phase overcurrent, out-of-step tripping, or loss-of-field according to PRC-026-1 – Attachment A. The 15 cycle threshold achieves a balance between the burden to the applicable entities and risk to the Bulk Electric System (BES) such that load-responsive protective relays are expected to not trip for a stable power swing. The 15 cycle threshold provides a practical and reasonable margin to ensure load-responsive protective relays with as little as a one or two cycle

intentional time delay would be applicable to the standard. The 15 cycle threshold in the standard was developed based upon engineering judgment through the standard development process.

NERC responds below to the Commission's question regarding what the increased burden would be if load-responsive protective relays set with an intentional time delay of 15 cycles or greater (i.e., zones 2, 3, 4, etc.) become applicable to PRC-026-1. The question applies to load-responsive protective relays that trip BES Elements due to stable or unstable power swings identified in either Requirement R1, Criterion 4 by the Planning Coordinator through a valid Planning Assessment and Requirement R2, Part 2.2 by the Generator Owner or Transmission Owner following an actual event.

Planning Coordinator

For the Planning Coordinator, there would be no increase in burden anticipated by the proposed question. The Planning Coordinator is required by Reliability Standard TPL-001-4 (*Transmission System Planning Performance Requirements*),[8] Requirement R4 to perform contingency analyses based on computer simulation models for the Stability portion of the annual Planning Assessment. The analyses determine whether the BES meets the performance requirements listed in TPL-001-4, Table 1 based on the Contingency list the Planning Coordinator identified that is expected to produce more severe System impacts on its portion of the BES. The Contingency analyses must simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent tripping of

[8] TPL-001-4 was approved by the Commission in Order No.786 (*see*, 145 FERC ¶61,051) (October 17, 2013), and will become enforceable on January 1, 2016.

Transmission lines and transformers where transient swings (i.e., stable or unstable power swings) cause Protection System operation based on generic or actual relay models. The Planning Assessment will reveal Elements with load-responsive protective relays having time delays of 15 cycles or greater that trip due to power swings. If these tripping Elements cause a violation of the performance criteria of TPL-001-4, the Planning Coordinator is required to mitigate these conditions through a Corrective Action Plan (CAP).[9] Therefore, mitigation of tripping under TPL-001-4 appropriately addresses the Commission's concern related to an Element that has been identified by a Planning Coordinator as potentially susceptible to power swings.

Requirement R1, Criterion 4 of proposed PRC-026-1 requires the Planning Coordinator to report to the applicable Generator Owner and/or Transmission Owner any Element tripping, regardless of time delay, due to stable and/or unstable power swings that are identified in a valid Planning Assessment. The intent of this criterion is to ensure a method of capturing any stable or unstable power swing that the Planning Coordinator observes as tripping Elements in addition to the locations that are expected to be susceptible to power swings as mandated by Requirement R1, Criteria 1, 2, and 3.

Generator Owner and Transmission Owner

Unlike the Planning Coordinator, requiring load-responsive protective relays with time delays of 15 cycles or greater stands to place additional burden on the Generator Owner and Transmission Owner for any Elements that are identified using Requirement R1, Criterion 4. For the Generator Owner and Transmission Owner, the increase in burden is dependent upon the

[9] 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." The *NERC Glossary of Terms* is *available at* http://www.nerc.com/pa/Stand/Pages/default.aspx.

Elements identified by the Planning Coordinator in Requirement R1, Criterion 4 and Elements identified by the Generator Owner and Transmission Owner in Requirement R2, Part 2.2 as described in the following two subsections.

Requirement R1, Criterion 4

Any additional burden on the Generator Owner and Transmission Owner would be determined by the increase in the quantity of load-responsive protective relays applied to that Element beyond what is proposed in PRC-026-1 (i.e. load-responsive protective relays with time delays of 15 cycles or greater). Since PRC-026-1 primarily addresses instantaneous and any other relays with an intentional time delay less than 15 cycles, an increase in the burden could be on the order of two or three times in magnitude to address zone 2 (not communication-aided) and application of reverse zone 3 and/or forward zone 4 remote back-up time delayed elements.

For the Transmission Owner, inclusion of load responsive protective relays with time delays of 15 cycles or greater could require an upgrade to the protection at each end of an Element with communication-aided protection to address zone 2. General industry practice is to set the zone 2 load-responsive protective relay time delayed element above the 15 cycle threshold proposed by PRC-026-1. Additionally, inclusion of load responsive relays with time delays of 15 cycles or greater may require power swing blocking (PSB) application on the reverse zone 3 and/or forward zone 4 remote back-up time delayed elements. Reverse zone 3 and/or forward zone 4 time delayed relay elements are applied at some line Element terminals to provide remote back-up protection for multiple protection system failures. These relay elements are typically set to reach much further than zone 2 time delayed relay elements, and typically have time delays of 40 cycles or greater. These relay elements, as typically set, will not be able to comply with PRC-026-1, Attachment B criteria. For these load-responsive protective relay

elements to meet the Attachment B criteria, their reaches may have to be significantly reduced, which will limit their effectiveness in providing dependable remote back-up protection. More likely, PSB relaying will have to be applied to block the reverse zone 3 and/or forward zone 4 remote back-up time delayed relay elements. If the relay is electromechanical, then a separate PSB relay will have to be installed, or the relay package at the line terminal will have to be upgraded to modern microprocessor relaying at a significant cost to ensure dependable tripping for faults. It is not common in the industry to apply PSB relaying to zone 3/zone 4 relays as they are generally not expected to be responsive to tripping for stable power swings due to their long time delay.

For the Generator Owner, inclusion of load responsive relays with time delays of 15 cycles or greater could unintentionally require non-standard loss-of-field (LOF) settings for generator protection, which protect generators from damage during a loss-of-field condition. Requiring LOF load-responsive protective relays that operate in time delays greater than 15 cycles to be applicable to PRC-026-1 could result in a loss of dependable tripping during a LOF condition. The outer LOF tripping zones typically have time delays of 15 cycles or greater and will not meet the PRC-026-1, Attachment B criteria using traditional industry accepted methods of applying settings. Inclusion of the LOF load-responsive protective relays that have time delays of 15 cycles or greater could require a reduction of the outer LOF zone reaches or require unconventional PSB of the LOF elements.

Requirement R2, Part 2.2

Reliability Standards that address relay loadability (e.g., PRC-023 and PRC-025) decrease the likelihood of a load-responsive protective relay tripping for a stable power swing. As described in NERC's petition, the largest reach of a zone 2 relay allowed by PRC-023-3 occurs when using the maximum power transfer criteria as shown in Requirement R1, Criterion

3 of PRC-023-3. If this criterion is used, the smallest system angle at the intersection of the swing trajectory with the zone 2 element is 108.8 degrees. Using Equation 1 from the PRC-026-1 Application Guidelines, assuming the stable swing begins to retreat at the stability boundary of 120 degrees, the slowest calculated slip rate that the zone 2 element could trip for using a time delay of 15 cycles is: $F_{slip} = 2 * (120 – 108.8) * 60 / (360 * 15) = 0.249$ Hz. Stable power swings that approach the stability boundary of 120 degrees will most likely be traveling at a slip rate of more than 0.25 Hz, and therefore, are not likely to cause tripping of the zone 2 time delayed relay element.

Any actual event that includes tripping of an Element due to a power swing is likely to be the result of a large event where instability, uncontrolled separation(s) or cascading outages occur. Placing an additional burden on the Generator Owner and Transmission Owner to address load-responsive protective relays with a time delay of 15 cycles and greater could require the owners to upgrade or replace more of its protection equipment than is technically necessary, thus increasing the burden. The likelihood of having a reoccurrence of the specific circumstances of a large actual event would be rare; and would therefore impose additional burden on the Generator Owner or Transmission Owner with little benefit to reliability.

Tripping unnecessarily other than a Fault due to an actual stable power swing would be classified as a Misoperation under PRC-004-4 (*Protection System Misoperation Identification and Correction*).[10] In addressing a Misoperation under PRC-004-4, the Generator Owner and Transmission Owner are required to develop a CAP or declare why such actions would not improve reliability. At a minimum, the Generator Owner and Transmission Owner are required to meet the reliability criteria of the proposed PRC-026-1 requirements. This means that any

[10] The PRC-004-4 standard was approved by the Commission on May 29, 2015 (*see*, 151 FERC ¶61,186), and will become enforceable on July 1, 2016.

load-responsive protective relay set with a time delay less than 15 cycles must meet the proposed PRC-026-1, Attachment B criteria. Under PRC-004-4, the Generator Owner and Transmission Owner are required to develop a CAP to address the cause(s) of the Misoperation, for example, tripping due to load-responsive protective relays set with a time delay of 15 cycles or greater, unless reliability would not be improved. This is responsive to the Commission's second question concerning burden by allowing the Generator Owner and Transmission Owner to mitigate reoccurrence without unnecessarily broadening the applicability of the proposed PRC-026-1 standard to include load-responsive protective relays with time delays of 15 cycles or greater. At a minimum, the Generator Owner and Transmission Owner must meet the PRC-026-1 criteria following an actual event regardless of the actions taken under PRC-004-4.

Addressing load-responsive protective relays under Requirement R2, Part 2.2 provides a reasonable assurance that the impacted Element will not trip in the future due to a stable power swing as discussed above. Likewise, should the Planning Coordinator identify in future studies the same Element that tripped due to an actual power swing, it will continue to be reported as an Element pursuant to Requirement R1, and the applicable Generator Owner and/or Transmission Owner will have an obligation to periodically evaluate the load-responsive protective relays on that Element.

This approach is consistent with the recommendations of the NERC System Protection and Control Subcommittee (SPCS) that are documented in the *Protection System Response to Power Swings*, August 2013 technical report.[11] The report recommends that the standard drafting team should consider certain criteria in establishing the applicability of the Reliability

[11] NERC System Protection and Control Subcommittee, Protection System Response to Power Swings, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 20 and 21.

Standard to limit applicability to only those transmission lines on which protective relays are most likely to trip during stable power swings (PRC-026-1, Requirement R1, Criteria 1-3). A fourth criteria (Requirement R1, Criterion 4) includes "[l]ines identified through other studies, including but not limited to, event analyses and transmission planning or operational planning assessments." This criterion captures tripping of Elements due to stable or unstable power swings in the planning environment that would not have been applicable to the first three criterion of PRC-026-1.

The SPCS document recommends that, based on its review of historical events, consideration of the trade-offs between dependability and security, and recognition of the indirect benefits of implementing a transmission relay loadability standard (PRC-023), a NERC Reliability Standard to address relay performance during stable swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability.[12] Accordingly, a power swing that causes tripping during an actual event may not necessarily require all of the load-responsive relays to be evaluated for susceptibility. The approach proposed by the standard, applicable to load-responsive protective relays with a time delay less than 15 cycles as outlined in PRC-026-1, Attachment A, provides sufficient mitigation of the risk to tripping due to stable power swings while balancing the burden and risk to the BES.

IV. Conclusion

NERC reaffirms its support of the 15 cycle threshold as a practical time delay with sufficient technical basis to assure a proper balance between security and dependability. Load responsive protective relay elements with time delays of 15 cycles or greater that trip during

[12] *Id.* at p. 24.

TPL-001-4 simulated events or that trip during an actual stable power swing system event will be mitigated through a CAP pursuant to TPL-001-4 and PRC-004-4.

The proposed PRC-026-1 standard addresses instantaneous load-responsive protective relays which have the greatest risk to tripping due to a stable power swing. Furthermore, a time delay of less than 15 cycles provides a definite margin to ensure that the addition of only one or two cycles of intentional time delay, for example, would not prevent the load-responsive protective relay from being applicable to the standard and undermine the reliability objective. Therefore, the specified time delay of less than 15 cycles is reasonable and practical while limiting the burden on the applicable Generator Owner and Transmission Owner. The 15 cycle threshold inherently provides a balance between the burden and risk to applicable Elements that could trip in response to a stable or unstable power swing.

Respectfully submitted,

/s/ Holly A. Hawkins

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Date: November 23, 2015

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 23rd day of November, 2015.

/s/ Holly A. Hawkins

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Associate Counsel for the North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

October 23, 2015

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: Clarifying Supplemental Information Updating Implementation Plan
Docket Nos. RD15-5-000, RD15-5-001, and RD15-6-000

Dear Secretary Bose:

On July 7, 2015, in accordance with the Federal Energy Regulatory Commission ("Commission") order on May 13, 2015 ("May 13th Order"),[1] NERC proposed revisions to the Violation Risk Factors ("VRF") for Requirements R1 through R6 of Reliability Standards PRC-004-3, PRC-004-4, and PRC-004-5 (*Protection System Misoperation Identification and Correction*).[2]

As noted in NERC's initial Petition for approval of Reliability Standard PRC-004-5 "Proposed Reliability Standard PRC-004-5 is intended to replace prior versions of PRC-004."[3] Similarly, PRC-004-4, which becomes effective on July 1, 2016 is intended to supersede and retire any prior version of the standard. NERC respectfully requests to supplement its pending Petition for Reliability Standard PRC-004-5 with the replacement Implementation Plan attached as Exhibit A to expressly clarify out of an abundance of caution that the Implementation Plan applies to Reliability Standard PRC-004-5(i) (reflecting the VRF revisions) and that upon effectiveness of Reliability Standard PRC-004-5(i), all prior versions of Reliability Standard PRC-004 will be retired. Similarly, for the avoidance of confusion, NERC seeks to supplement its errata pending in Docket No. RD15-6-000 to provide an updated Implementation Plan on Reliability Standard PRC-004-4.[4] NERC requests that the Commission accept the Implementation Plans as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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1 *See N. Am. Elec. Reliability Corp.*, 151 FERC ¶ 61,129, at PP 2 and 20 (2015) ("May 13th Order"). *See also, N. Am. Elec. Reliability Corp.*, 151 FERC ¶ 61,186, at n. 4 (2015).

2 *Revisions of the North American Electric Reliability Corporation to the Violation Risk Factors for Reliability Standards PRC-004-3, PRC-004-4 and PRC-004-5*, Docket Nos. RD15-5-001, et. al (filed Jul. 7, 2015).

3 *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards PRC-004-5 and PRC-010-2*, Docket No. RD15-5-000 (filed June 8, 2015) ("Petition").

4 *Errata to Petitions of the North American Electric Reliability Corporation for Approval of Reliability Standards BAL-003-1, COM-001-2 VAR-001-4 and Implementation Plan for Reliability Standard PRC-004-4*, Docket No. RD15-6-000 (filed Aug. 25, 2015).

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Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in Docket Nos. RD15-5-000, RD15-5-001, and RD15-6-000.

Dated at Washington, D.C. this 23rd day of October, 2015.

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Exhibit A

PRC-004-4(i) Reliability Standard

Clean and Redline Implementation Plan

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Dispersed Generation Resources
PRC-004-4(i)

Standards Involved

Approval:

- PRC-004-4(i) – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-3 – Protection System Misoperation Identification and Correction
- PRC-004-2.1(i)a - Protection System Misoperation Identification and Correction

Prerequisite Approvals:

- PRC-004-3 – Protection System Misoperation Identification and Correction[1]

Background

In light of the adoption of a revised Bulk Electric System definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised Bulk Electric System definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

General Considerations

PRC-004-4 was proposed for approval to align the applicability section of PRC-004-3 with the revised definition of the Bulk Electric System. The intent of the SDT was to allow for flexibility of the PRC-004 applicability section regardless of the version that is currently in effect when an applicable governmental authority acts on the PRC-004-3 filing. PRC-004-2.1a was in effect as PRC-004-3 (developed in Project 2010-05.1) was pending regulatory approval. It was contemplated that depending on the timing of approvals for various versions of PRC-004, that PRC-004-2.1a might still be in effect at the time the revised definition of Bulk Electric System becomes effective for all entities. If this occurs, PRC-004-2.1(i)a will go into effect and PRC-004-4(i) shall go into effect after the technical revisions

[1] PRC-004-3 was adopted by the NERC Board of Trustees on August 18, 2014.

developed in Project 2010-05.1 are approved by applicable regulators, or as otherwise provided for in jurisdictions that do not require regulatory approvals.

Effective Date

PRC-004-4(i) shall become effective on the later of the effective date of PRC-004-3, or the date that PRC-004-4 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 either on the first day of the first calendar quarter after the date PRC-004-4 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction, or 12 months following the effective date of PRC-004-3, whichever is later.

Retirement of Existing Standards:

The existing standard, PRC-004-3 and PRC-004-2.1(i)a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-4.

For clarity, note that this Implementation Plan intends that upon effectiveness of the Reliability Standard PRC-004-4(i) all prior versions of Reliability Standard PRC-004 will be retired.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Dispersed Generation Resources

PRC-004-4(i)

Standards Involved

Approval:

- PRC-004-4(i) – Protection System Misoperation Identification and Correction

Retirement:

- PRC-004-3 – Protection System Misoperation Identification and Correction
- PRC-004-2.1(i)a - Protection System Misoperation Identification and Correction

Prerequisite Approvals:

- PRC-004-3 – Protection System Misoperation Identification and Correction[1]

Background

In light of the adoption of a revised Bulk Electric System definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-004, are necessary to align with the implementation of the revised Bulk Electric System definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Power Producing Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Power System.

General Considerations

PRC-004-4 ~~is~~ was proposed for approval to align the applicability section of PRC-004-3 with the revised definition of the Bulk Electric System. The intent of the SDT was to allow for flexibility of the PRC-004 applicability section regardless of the version that is currently in effect when an applicable governmental authority acts on the PRC-004-3 filing. ~~Currently,~~ PRC-004-2.1a ~~is~~ was in effect as PRC-004-3 (developed in Project 2010-05.1) ~~is~~ was pending regulatory approval. It was contemplated that ~~D~~depending on the timing of approvals for various versions of PRC-004, that PRC-004-2.1a ~~may~~ might still be in effect at the time the revised definition of Bulk Electric System becomes effective for all entities. If this occurs, PRC-004-2.1(i)a will go into effect and PRC-004-4(i) shall go into effect after the

[1] PRC-004-3 was adopted by the NERC Board of Trustees on August 18, 2014.

technical revisions developed in Project 2010-05.1 are approved by applicable regulators, or as otherwise provided for in jurisdictions that do not require regulatory approvals.

Effective Date

PRC-004-4(i) shall become effective on the later of the effective date of PRC-004-3, or the date that PRC-004-4 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 either on the first day of the first calendar quarter after the date ~~the standard~~ PRC-004-4 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction, or 12 months following the effective date of PRC-004-3, whichever is later.

Retirement of Existing Standards:

The existing standard, PRC-004-3 and PRC-004-2.1(i)a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-4.

For clarity, note that this Implementation Plan intends that upon effectiveness of the Reliability Standard PRC-004-4(i) all prior versions of Reliability Standard PRC-004 will be retired.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

PRC-004-5(i) Reliability Standard

Clean and Redline Implementation Plan

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

PRC-004-5(i) – Protection System Misoperation Identification and Correction

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-004-5(i) – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-004-4 – Protection System Misoperation Identification and Correction[1]

Prerequisite Approvals

- PRC-010-2 – Undervoltage Load Shedding

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occurring soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-004-5. The standard PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version two of PRC-010 is including undervoltage load shedding (UVLS) that is included in a UVLS Program.

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider

[1] For clarity, note that this Implementation Plan intends that upon effectiveness of the Reliability Standard PRC-004-5(i) all prior versions of Reliability Standard PRC-004 will be retired..

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Effective Dates

PRC-004-5(i) shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after 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 later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date PRC-004-5 is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

PRC-004-5(i) – Protection System Misoperation Identification and Correction

Project 2008-02.2 – Phase 2 UVLS: Misoperations

Requested Approvals

- PRC-004-5(i) – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-004-4 – Protection System Misoperation Identification and Correction[1]

Prerequisite Approvals

- PRC-010-2 – Undervoltage Load Shedding

General Considerations

The implementation period is intended to align with the Effective Date of PRC-010-1 or occurring soon thereafter in order to incorporate certain aspects of PRC-022-1 – Under-Voltage Load Shedding Program Performance into PRC-004-5. The standard PRC-022-1 was retired by PRC-010-1. The Implementation Plan for PRC-010-1[2] allows twelve (12) calendar months after applicable approvals. Version two of PRC-010 is including undervoltage load shedding (UVLS) that is included in a UVLS Program.

Applicable Entities

- Transmission Owner
- Generator Owner
- Distribution Provider

[1] For clarity, note that this Implementation Plan intends that upon effectiveness of the Reliability Standard PRC-004-5(i) all prior versions of Reliability Standard PRC-004 will be retired. ~~PRC-004-4 was adopted by the NERC Board of Trustees on November 13, 2014. PRC-004-4 is pending adoption or approval by applicable governmental authorities. PRC-004-5 will retire PRC-004-3 if PRC-004-4 is not adopted or approved by an applicable governmental authority~~.

[2] Refer to Project 2008-02.2 on the NERC website. (http://www.nerc.com/pa/Stand/Pages/Project-2008-02_2-Phase-2-Undervoltage-Load-Shedding-UVLS-Misoperations.aspx)

Effective Dates

PRC-004-5(i) shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after 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 later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the date PRC-004-5~~the standard~~ is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

20151119-3123 FERC PDF (Unofficial) 11/19/2015

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD15-5-000

November 19, 2015

North American Electric Reliability Corporation
1325 G Street, NW
Suite 600
Washington, D.C. 20005

Attention: Holly A. Hawkins, Associate General Counsel
North American Electric Reliability Corporation

Reference: Petition for Approval of Proposed Reliability Standards PRC-004-5 and PRC-010-2

Dear Ms. Hawkins:

On June 8, 2015, and as supplemented on October 23, 2015, the North American Electric Reliability Corporation (NERC) filed a petition seeking approval of Reliability Standards PRC-004-5 (Protection System Misoperation Identification and Correction) and PRC-010-2 (Undervoltage Load Shedding), and implementation plan.[1]

NERC explains that Reliability Standards PRC-004-5 and PRC-010-2 were developed in response to an Order No. 693 directive that NERC develop modifications to Reliability Standard PRC-010-0 to require an integrated and coordinated approach in all

[1] On October 23, 2015, NERC submitted a supplemental filing for this and two related dockets (RD15-5-001 and RD15-6-000) concerning proposed revisions to the Violation Risk Factors for certain requirements in Reliability Standards PRC-004-3, PRC-004-4 and PRC-004-5. NERC's supplemental filing includes an Implementation Plan that applies to Reliability Standard PRC-004-5(i). NERC states that, when PRC-004-5(i) becomes effective, it will replace all prior versions of Reliability Standard PRC-004.

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protection systems, including UVLS programs.[2] NERC states that the purpose of the two modified Reliability Standards is to ensure that undervoltage load shedding (UVLS) protective relay misoperations are identified and corrected, and that UVLS equipment performance is appropriately evaluated. Reliability Standard PRC-004-5 is applicable to Distribution Providers, Generation Owners, and Transmission Owners. Reliability Standard PRC-010-2 is applicable to Planning Coordinators and Transmission Planners, as well as Distribution Providers and Transmission Owners that own, operate or control UVLS equipment under the UVLS Program established by the Transmission Planner or Planning Coordinator.

NERC states that Reliability Standard PRC-004-5 is revised to apply to UVLS protection systems that are intended to trip one or more bulk electric system elements. According to NERC, Reliability Standard PRC-010-2 includes revisions to Requirement R4 to expressly require the evaluation of UVLS program equipment performance, with a conforming change to Requirement R5. NERC explains that Reliability Standard PRC-010-2 updates PRC-010-1 "by explicitly addressing the operations/nonoperation (i.e., Misoperation) of UVLS Equipment to avoid a gap in coverage due to the retirement of Reliability Standard PRC-022-1."[3] Further, NERC states that PRC-010-2 "achieves this by expressly referencing performance (i.e., operation/non-operation) of the UVLS Program equipment at Requirement R4 with a conforming update to Requirement R5 to specifically reference the assessment performed in Requirement R4."[4]

NERC's filing was noticed on June 9, 2015, with comments, interventions and protests due on or before July 9, 2015. NERC's October 23, 2015 supplemental filing was noticed on October 27, 2015, with interventions, comments and protests due on or before November 3, 2015. No timely interventions or comments were filed.[5]

NERC's uncontested filing is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303, effective as of the date of this order.

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[2] *Mandatory Reliability Standards for the Bulk Electric System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1509, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[3] Petition at 13.

[4] *Id.*

[5] Peak Reliability submitted an Out-Of-Time motion to intervene and comment. On August 20, 2015, Peak Reliability repeated and expanded upon its points in comments it submitted in Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. The Commission addressed those points in the Final Rule for those dockets. [**OSEC to provide CITE to FINAL RULE**]

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This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(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 the issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

20151119-3123 FERC PDF (Unofficial) 11/19/2015

Document Content(s)

RD15-5-000.DOCX.....1-3

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD15-6-000

November 13, 2015

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Andrew C. Wills
Associate Counsel for North American Electric Reliability Corporation

Reference: Errata to Petitions of the North American Electric Reliability Corporation for Approval of Reliability Standards BAL-003-1, COM-001-2, VAR-001-4 and Implementation Plan for Reliability Standard PRC-004-4.

Dear Mr. Wills:

On August 25, 2015, the North American Electric Reliability Corporation (NERC) filed a petition seeking approval of errata to three Reliability Standards: BAL-003-1 (Frequency Response Bias Setting), COM-001-2 (Communications), and VAR-001-4 (Voltage and Reactive Control) and to the implementation plan of Reliability Standard PRC-004-4 (Protection System Misoperation Identification and Correction), which have each been previously filed with the Commission and subsequently approved as mandatory and enforceable. The consolidated errata filing corrects certain inadvertent errors in the three Reliability Standards and implementation plan, including various formatting and stylistic revisions, language clarifications, and minor corrections.

For Reliability Standard BAL-003-1, approved by the Commission in Order No. 794,[1] the errata filing corrects several inadvertent numbering errors, as well as font inconsistencies in Measure M4.

[1] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014).

For Reliability Standard COM-001-2, approved by the Commission in Order No. 808,[2] the errata filing corrects inadvertent numbering errors in the parts to Requirement R6.

For Reliability Standard VAR-001-4, approved by the Commission by letter order,[3] the errata filing adds the word "or" to Requirement R5, part 5.3, between the words "schedules" and "Reactive."

For Reliability Standard PRC-004-4, the errata filing modifies the implementation plan to clarify that Reliability Standard PRC-004-2.1(i)a will retire upon effectiveness of PRC-004-4.

NERC's filing was noticed on August 25, 2015, with interventions, comments and protests due on or before September 28, 2015. No comments were received.

NERC filed supplemental information on the implementation plan for Reliability Standard PRC-004-4, *inter alia*, on October 23, 2015, clarifying that upon effectiveness of Reliability Standard PRC-004-4(i), all prior versions of Reliability Standard PRC-004 would be retired. NERC's supplemental filing was noticed on October 27, 2015, with interventions, comments and protests due on or before November 3, 2015. No comments were received.

NERC's uncontested filing is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2015), effective as of the date of this order.[4]

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[2] *Communications Reliability Standard,* Order No. 808, 151 FERC ¶ 61,039 (2015).

[3] *North American Electric Reliability Corp.*, Docket No. RD14-11-000 (Aug. 1, 2014) (delegated letter order).

[4] The reporting and recordkeeping requirements and burden related to the following Reliability Standards were approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act, as noted:

- BAL-003-1, in FERC-725R (OMB Control No. 1902-0268)
- COM-001-2, in FERC-725V (OMB Control No. 1902-0277)
- VAR-001-4, in FERC-725A and FERC-725X (OMB Control Nos. 1902-0244 and 1902-0278)
- The burden for PRC-004-2a (unchanged in Order 785 in RM12-16) and for PRC-004-2.1a (which replaced Reliability Standard PRC-004-2a) is covered under FERC-725A (OMB Control No. 1902-0244). The burden related to PRC-004-3 (under FERC-725G1) was submitted to OMB on August 26, 2015 and is currently

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

pending OMB review (ICR #201508-1902-004). PRC-004-4 (FERC Docket No. RD15-3) was submitted to OMB for information only.

The actions in this order do not affect those burden estimates as approved or as submitted for review, so this material will be provided to OMB for information only.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RC11-6-004

Friday, November 13, 2015

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Gizelle Wray
Associate Counsel for North American Electric Reliability Corporation

Reference: Annual Report on the Find, Fix, Track, and Report Program

Dear Ms. Wray:

On September 18, 2015, the North American Electric Reliability Corporation (NERC) filed its annual report on the Find, Fix, Track and Report (FFT) Program to comply with the Commission's June 20, 2013 order[1] and September 18, 2014 order.[2] In addition to reporting on the status of the program, the filing also indicates NERC's intention to combine the evaluation of Compliance Exceptions with the annual sampling of FFTs to further streamline oversight of the FFT and compliance exception programs.

NERC's filing was noticed on September 23, 2015, with interventions, comments and protests due on or before October 19, 2015. There were no interventions, comments or protests filed.

NERC's uncontested filing is hereby accepted 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

[1] North American Electric Reliability Corp., 143 FERC ¶ 61,253 (2013).
[2] North American Electric Reliability Corp., 148 FERC ¶ 61,214 (2014).

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

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

North American Electric Reliability Corporation
Docket No. RR15-19-000

November 20, 2015

North American Electric Reliability Corporation
1325 G Street NW, Suite 600
Washington, DC 20005

Attention: Stefan C. Bergere
Associate Counsel

Reference: Amendments to Delegation Agreement

Dear Mr. Bergere:

On September 16, 2015, North American Electric Reliability Corporation (NERC) submitted proposed amendments to its delegation agreement with Southwest Power Pool, Inc. (SPP), specifically amendments to SPP's Bylaws.

Notice of this filing was issued on September 16, 2015, with protests and interventions due on or before October 7, 2015. 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

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Revised Critical Infrastructure Protection Reliability Standards — Docket No. RM15-14-000

NOTICE OF TECHINICAL CONFERENCE

(October 28, 2015)

Take notice that the Federal Energy Regulatory Commission (Commission) will hold a Commission staff-led technical conference on Critical Infrastructure Protection Supply Chain Risk Management issues identified in the Notice of Proposed Rulemaking (NOPR) in the above-captioned docket on January 28, 2016. The conference will begin at 9:00 am and end at approximately 5:00 pm (Eastern Time). The conference will be held at the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

The technical conference shall facilitate a structured dialogue on supply chain risk management issues identified by the Commission in the Revised Critical Infrastructure Protection (CIP) Standards NOPR. Technical Conference panelists may be asked to address: (1) the NOPR proposal to direct that NERC develop a Reliability Standard to address supply chain risk management; (2) the anticipated features of, and requirements that should be included in, such a standard; and (3) a reasonable timeframe for development of a standard. The technical conference will be led by Commission staff, with prepared remarks to be presented by invited panelists, which must be submitted to the Commission in advance of the conference. A subsequent notice providing an agenda and details on the topics for discussion will be issued in advance of the conference. Commissioners may attend and participate.

There is no fee for attendance. However, members of the public are encouraged to preregister online at: https://www.ferc.gov/whats-new/registration/01-28-16-form.asp

Those wishing to participate in panel discussions should submit nominations no later than close of business on November 20, 2015 online at: https://www.ferc.gov/whats-new/registration/01-28-16-speaker-form.asp

There will be no webcast of this event. However, it will be transcribed. Transcripts of the conference will be immediately available for a fee from Ace-Federal Reporters, Inc. (202-347-3700).

Commission conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations please send an email to accessibility@ferc.gov or call toll free (866) 208-3372 (voice) or (202) 502-8659 (TTY), or send a fax to (202) 208-2106 with the requested accommodations.

For more information about the technical conference, please contact:

Sarah McKinley
Office of External Affairs
202-502-8368 sarah.mckinley@ferc.gov

Kimberly D. Bose,
Secretary.

153 FERC ¶ 61,178
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM15-16-000, Order No. 817]

Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards

(Issued November 19, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission approves revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards, developed by the North American Electric Reliability Corporation, which the Commission has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory Reliability Standards. The Commission also directs NERC to make three modifications to the standards within 18 months of the effective date of the final rule.

EFFECTIVE DATE: This rule will become effective **[60 days after publication in the FEDERAL REGISTER].**

FOR FURTHER INFORMATION CONTACT:

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Washington, DC 20426
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SUPPLEMENTARY INFORMATION:

153 FERC ¶ 61,178
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards — Docket No. RM15-16-000

ORDER NO. 817

FINAL RULE

(Issued November 19, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves revisions to the Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) Reliability Standards, developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). The TOP and IRO Reliability Standards improve on the currently-effective standards by providing a more precise set of Reliability Standards addressing operating responsibilities and improving the delineation of responsibilities between applicable entities. The revised TOP Reliability Standards eliminate gaps and ambiguities in the currently-effective TOP requirements and improve efficiency by

[1] 16 U.S.C. 824o (2012).

incorporating the necessary requirements from the eight currently-effective TOP Reliability Standards into three comprehensive Reliability Standards. Further, the standards clarify and improve upon the currently-effective TOP and IRO Reliability Standards by designating requirements in the proposed standards that apply to transmission operators for the TOP standards and reliability coordinators for the IRO standards. Thus, we conclude that there are benefits to clarifying and bringing efficiencies to the TOP and IRO Reliability Standards, consistent with the Commission's policy promoting increased efficiencies in Reliability Standards and reducing requirements that are either redundant with other currently-effective requirements or have little reliability benefit.[2]

2. The Commission also finds that NERC has adequately addressed the concerns raised by the Commission in the Notice of Proposed Rulemaking issued in November 2013 concerning the proposed treatment of system operating limits (SOLs) and interconnection reliability operating limits (IROLs) and concerns about outage coordination.[3] Further, the Commission approves the definitions for operational

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[2] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (2013).

[3] Monitoring System Conditions - *Transmission Operations Reliability Standard, Transmission Operations Reliability Standards, Interconnection Reliability Operations and Coordination Reliability Standards*, Notice of Proposed Rulemaking, 145 FERC ¶ 61,158 (2013) (Remand NOPR). Concurrent with filing the proposed TOP/IRO standards in the immediate proceeding, NERC submitted a motion to withdraw the earlier petition that was the subject of the Remand NOPR. No protests to the motion were filed and the petition was withdrawn pursuant to 18 CFR 385.216(b).

planning analysis and real-time assessment, the implementation plans and the violation severity level and violation risk factor assignments. However, the Commission directs NERC to make three modifications to the standards as discussed below within 18 months of the effective date of this Final Rule.

3. We also address below the four issues for which we sought clarifying comments in the June 18, 2015, Notice of Proposed Rulemaking (NOPR) proposing to approve the TOP and IRO Reliability Standards: (A) possible inconsistencies in identifying IROLs; (B) monitoring of non-bulk electric system facilities; (C) removal of the load-serving entity as an applicable entity for proposed Reliability Standard TOP-001-3; and (D) data exchange capabilities. In addition we address other issues raised by commenters.

I. Background

A. Regulatory Background

4. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[4] Once approved, the Reliability Standards may be enforced by the ERO

[4] 16 U.S.C. 824o(c) and (d).

subject to Commission oversight, or by the Commission independently.[5] In 2006, the Commission certified NERC as the ERO pursuant to FPA section 215.[6]

5. The Commission approved the initial TOP and IRO Reliability Standards in Order No. 693.[7] On April 16, 2013, in Docket No. RM13-14-000, NERC submitted for Commission approval three revised TOP Reliability Standards to replace the eight currently-effective TOP standards.[8] Additionally, on April 16, 2013, in Docket No. RM13-15-000, NERC submitted for Commission approval four revised IRO Reliability Standards to replace six currently-effective IRO Reliability Standards. On November 21, 2013, the Commission issued the Remand NOPR in which the Commission expressed concern that NERC had "removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these

[5] *See id.* 16 U.S.C. 824o(e).

[6] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[7] *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 508, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). In addition, in Order No. 748, the Commission approved revisions to the IRO Reliability Standards. *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, Order No. 748, 134 FERC ¶ 61,213 (2011).

[8] On April 5, 2013, in Docket No. RM13-12-000, NERC proposed revisions to Reliability Standard TOP-006-3 to clarify that transmission operators are responsible for monitoring and reporting available transmission resources and that balancing authorities are responsible for monitoring and reporting available generation resources.

aspects in the proposed standards."[9] The Commission identified two main concerns and asked for clarification and comment on a number of other issues. Among other things, the Commission expressed concern that the proposed TOP Reliability Standards did not require transmission operators to plan and operate within all SOLs, which is a requirement in the currently-effective standards. In addition, the Commission expressed concern that the proposed IRO Reliability Standards did not require outage coordination.

B. NERC Petition

6. On March 18, 2015, NERC filed a petition with the Commission for approval of the proposed TOP and IRO Reliability Standards.[10] As explained in the Petition, the proposed Reliability Standards consolidate many of the currently-effective TOP and IRO Reliability Standards and also replace the TOP and IRO Reliability Standards that were the subject of the Remand NOPR. NERC stated that the proposed Reliability Standards include improvements over the currently-effective TOP and IRO Reliability Standards in (1) operating within SOLs and IROLs; (2) outage coordination; (3) situational awareness; (4) improved clarity and content in foundational definitions; and (5) requirements for operational reliability data. NERC stated that the proposed TOP and IRO Reliability Standards address outstanding Commission directives relevant to the proposed TOP and

[9] Remand NOPR, 145 FERC ¶ 61,158 at P 4.

[10] The TOP and IRO Reliability Standards are not attached to the Final Rule. The complete text of the Reliability Standards is available on the Commission's eLibrary document retrieval system in Docket No. RM15-16 and is posted on the ERO's web site, *available at*: http://www.nerc.com.

IRO Reliability Standards. NERC stated that the proposed Reliability Standards provide a comprehensive framework for reliable operations, with important improvements to ensure the bulk electric system is operated within pre-established limits while enhancing situational awareness and strengthening operations planning. NERC explained that the proposed Reliability Standards establish or revise requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. NERC contended that the proposed Reliability Standards help to ensure that reliability coordinators and transmission operators work together, and with other functional entities, to operate the bulk electric system within SOLs and IROLs.[11] NERC also provided explanations of how the proposed Reliability Standards address the reliability issues identified in the report on the Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations ("2011 Southwest Outage Blackout Report").

7. NERC proposed three TOP Reliability Standards to replace the existing suite of TOP standards. The proposed TOP Reliability Standards generally address real-time operations and planning for next-day operations, and apply primarily to the responsibilities and authorities of transmission operators, with certain requirements

[11] The NERC Glossary of Terms defines IROL as "[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System." In turn, NERC defines SOL as "[t]he 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…."

applying to the roles and responsibilities of the balancing authority. Among other things, NERC stated that the proposed revisions to the TOP Reliability Standards help ensure that transmission operators plan and operate within all SOLs. The proposed IRO Reliability Standards, which complement the proposed TOP Standards, are designed to ensure that the bulk electric system is planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions. The proposed IRO Reliability Standards set forth the responsibility and authority of reliability coordinators to provide for reliable operations. NERC stated that, in the proposed IRO Reliability Standards, reliability coordinators must continue to monitor SOLs in addition to their obligation in the currently effective Reliability Standards to monitor and analyze IROLs. These obligations require reliability coordinators to have the wide-area view necessary for situational awareness and provide them the ability to respond to system conditions that have the potential to negatively affect reliable operations.

8. NERC also proposed revised definitions for "operational planning analysis" and "real-time assessment." For all standards except proposed Reliability Standards TOP-003-3 and IRO-010-2, NERC proposed the effective date to be the first day of the first calendar quarter twelve months after Commission approval. According to NERC's implementation plan, for proposed TOP-003-3, all requirements except Requirement R5 will become effective on the first day of the first calendar quarter nine months after the date that the standard is approved. For proposed IRO-010-2, Requirements R1 and R2 would become effective on the first day of the first calendar quarter that is nine months after the date that the standard is approved. Proposed TOP-003-3, Requirement R5 and

IRO-010-2, Requirement R3 would become effective on the first day of the first calendar quarter twelve months after the date that the standard is approved. The reason for the difference in effective dates for proposed TOP-003-3 and IRO-010-2 is to allow applicable entities to have time to properly respond to the data specification requests from their reliability coordinators, transmission operators, and/or balancing authorities.

C. Notice of Proposed Rulemaking

9. On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking proposing to approve the TOP and IRO Reliability Standards pursuant to FPA section 215(d)(2), along with the two new definitions referenced in the proposed standards, the assigned violation risk factors and violation severity levels, and the proposed implementation plan for each standard.[12]

10. In the NOPR, the Commission explained that the proposed TOP and IRO Reliability Standards improve on the currently-effective standards by providing a more precise set of Reliability Standards addressing operating responsibilities and improving the delineation of responsibilities between applicable entities. The Commission also proposed to find that NERC has adequately addressed the concerns raised by the Remand NOPR issued in November 2013.

[12] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, 151 FERC ¶ 61,236 (2015) (NOPR).

11. In the NOPR, the Commission also discussed the following specific matters and asked for further comment: (A) possible inconsistencies in identifying IROLs; (B) monitoring of non-bulk electric system facilities; (C) removal of the load-serving entity as an applicable entity for proposed Reliability Standard TOP-001-3; and (D) data exchange capabilities.

12. Timely comments on the NOPR were filed by: NERC; Arizona Public Service Company (APS), Bonneville Power Administration (BPA), Dominion Resources Services, Inc. (Dominion), the Edison Electric Institute (EEI); Electric Reliability Council of Texas, Inc. (ERCOT), Independent Electricity System Operator (IESO), ISO/RTOs,[13] International Transmission Company (ITC); Midcontinent Independent System Operator, Inc., Northern Indiana Public Service Company (NIPSCO), Occidental Energy Ventures, LLC (Occidental), Peak Reliability (Peak), and Transmission Access Policy Study Group (TAPS).

II. Discussion

13. Pursuant to section 215(d) of the FPA, we adopt our NOPR proposal and approve NERC's revisions to the TOP and IRO Reliability Standards, including the associated definitions, violation risk factors, violation severity levels, and implementation plans, as just, reasonable, not unduly discriminatory or preferential and in the public interest. We

[13] ISO/RTOs include Independent Electricity System Operator, ISO New England Inc., Midcontinent Independent System Operator, New York Independent System Operator, Inc., PJM Interconnection LLC, and Southwest Power Pool, Inc.

note that all of the commenters that address the matter support, or do not oppose, approval of the revised suite of TOP and IRO Reliability Standards. We determine that NERC's approach of consolidating requirements and removing redundancies generally has merit and is consistent with Commission policy promoting increased efficiencies in Reliability Standards and reducing requirements that are either redundant with other currently-effective requirements or have little reliability benefit.[14]

14. We also determine that the proposed TOP and IRO Reliability Standards should improve reliability by defining an appropriate division of responsibilities between reliability coordinators and transmission operators.[15] The proposed TOP Reliability Standards will eliminate multiple TOP standards, resulting in a more concise set of standards, reducing redundancy and more clearly delineating responsibilities between applicable entities. In addition, we find that the proposed 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. The TOP and IRO Reliability Standards address the coordinated efforts to plan and reliably operate the bulk electric system under both normal and abnormal conditions.

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[14] *See* Order No. 788, 145 FERC ¶ 61,147.

[15] *See, e.g.*, Order No. 748, 134 FERC ¶ 61,213, at PP 39-40.

15. In the NOPR, the Commission proposed to find that NERC adequately addressed the concerns raised by the Commission in the Remand NOPR with respect to (1) the treatment of SOLs in the proposed TOP Reliability Standards, and (2) the IRO standards regarding planned outage coordination, both of which we address below.

Operational Responsibilities and Actions of SOLs and IROLs

16. In the Remand NOPR, the Commission expressed concern that the initially proposed (now withdrawn) TOP standards did not have a requirement for transmission operators to plan and operate within all SOLs. The Commission finds that the TOP Reliability Standards that NERC subsequently proposed address the Commission's Remand NOPR concerns by requiring transmission operators to plan and operate within all SOLs, and to monitor and assess SOL conditions within and outside a transmission operator's area. Further, the TOP/IRO Standards approved herein 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. Likewise, the Reliability Standards give reliability coordinators the authority to direct actions to prevent or mitigate instances of exceeding IROLs because the primary decision-making authority for mitigating IROL exceedances is assigned to reliability coordinators while transmission operators have the primary responsibility for mitigating SOL exceedances.[16]

[16] *See* Remand NOPR, 145 FERC ¶ 61,158 at P 85. Further, currently-effective Reliability Standard IRO-009-1, Requirement R4 states that "[w]hen actual system

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17. Furthermore, the revised definitions of operational planning analysis and real-time assessment are critical components of the proposed TOP and IRO Reliability Standards and, together with the definitions of SOLs, IROLs and operating plans, work to ensure that reliability coordinators, transmission operators and balancing authorities plan and operate the bulk electric system within all SOLs and IROLs to prevent instability, uncontrolled separation, or cascading. In addition, the revised definitions of operational planning analysis and real-time assessment address other concerns raised in the Remand NOPR as well as multiple recommendations in the 2011 Southwest Outage Blackout Report.[17]

Outage Coordination

18. In the NOPR, the Commission explained that NERC had addressed concerns raised in the Remand NOPR with respect to the IRO standards regarding planned outage coordination. In the Remand NOPR, the Commission expressed concern with NERC's proposal because Reliability Standards IRO-008-1, Requirement R3 and IRO-010-1a (subjects of the proposed remand and now withdrawn by NERC) did not require the

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conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's T_V."

[17] NERC Petition at 17-18.

coordination of outages, noting that outage coordination is a critical reliability function that should be performed by the reliability coordinator.[18]

19. In the NOPR, the Commission noted that Reliability Standard IRO-017-1, Requirement R1 requires each reliability coordinator to develop, implement and maintain an outage coordination process for generation and transmission outages within its reliability coordinator area. Additionally, Reliability Standard IRO-014-3, Requirement R1, Part 1.4 requires reliability coordinators to include the exchange of planned and unplanned outage information to support operational planning analyses and real-time assessments in the operating procedures, processes, and plans for activities that require coordination with adjacent reliability coordinators. We believe that these proposed standards adequately address our concerns with respect to outage coordination as outlined in the Remand NOPR. However, as we discuss below we direct NERC to modify the standards to include transmission operator monitoring of non-BES facilities, and to specify that data exchange capabilities include redundancy and diverse routing; as well as testing of the alternate or less frequently used data exchange capability, within 18 months of the effective date of this Final Rule.

20. Below we discuss the following matters: (A) possible inconsistencies of identifying IROLs; (B) monitoring of non-bulk electric system facilities; (C) removal of

[18] Remand NOPR, 145 FERC ¶ 61,158 at P 90.

the load-serving entity function from proposed Reliability Standard TOP-001-3; (D) data exchange capabilities, and (E) other issues raised by commenters.

A. Possible Inconsistences in IROLs Across Regions

NOPR

21. In the NOPR, the Commission noted that in Exhibit E (SOL White Paper) of NERC's petition, NERC stated that, with regard to the SOL concept, the SOL White Paper brings "clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances."[19] The Commission further noted that IROLs, as defined by NERC, are a subset of SOLs that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk electric system. The Commission agreed with NERC that clarity and consistency are important with respect to establishing and implementing operating plans to mitigate SOL and IROL exceedances. However, the Commission noted that NERC, in its 2015 State of Reliability report, had stated that the Western Interconnection reliability coordinator definition of an IROL has additional criteria that may not exist in other reliability coordinator areas.[20] The Commission stated

[19] NERC Petition, Exhibit E, "White Paper on System Operating Limit Definition and Exceedance Clarification" at 1.

[20] NOPR, 151 FERC ¶ 61,236 at P 51, citing NERC 2015 State of Reliability report at 44, *available at* www.nerc.com. *See also* WECC Reliability Coordination System Operating Limits Methodology for the Operations Horizon, Rev. 7.0 (effective March 3, 2014) at 18 (stating that "SOLs qualify as IROLs when … studies indicate that instability, Cascading, or uncontrolled separation may occur resulting in uncontrolled

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that it is unclear whether NERC regions apply a consistent approach to identifying IROLs. The Commission, therefore, sought comment on (1) identification of all regional differences or variances in the formulation of IROLs; (2) the potential reliability impacts of such differences or variations, and (3) the value of providing a uniform approach or methodology to defining and identifying IROLs.

Comments

22. Commenters generally agree that there are variations in IROL formulation but maintain that the flexibility is needed due to different system topographies and configurations. EEI and other commenters, also suggest that, to the extent there are variations, such resolution should be addressed by NERC and the Regional Entities in a standard development process rather than by a Commission directive. NERC requests that the Commission refrain from addressing these issues in this proceeding. NERC contends that the TOP and IRO Reliability Standards do not address the methods for the development and identification of SOLs and IROLs and that requirements governing the development and identification of SOLs and IROLs are included in the Facilities Design, Connections and Maintenance (FAC) Reliability Standards. NERC states that the current FAC Reliability Standards provide reliability coordinators flexibility in the manner in

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interruption of load equal to or greater than 1000 MW"), *available at* https://www.wecc.biz/Reliability/PhaseII%20WECC%20RC%20SOL%20Methodology%20FINAL.pdf.

which they identify IROLs.[21] NERC adds that it recently initiated a standards development project (Project 2015-09 Establish and Communicate System Operating Limits) to evaluate and modify the FAC Reliability Standards that address the development and identification of SOLs and IROLs. NERC explains that the Project 2015-09 standard drafting team will address the clarity and consistency of the requirements for establishing both SOLs and IROLs. According to NERC, it would be premature for NERC or the Commission to address issues regarding the identification of IROLs in this proceeding without the benefit of the complete analysis of the Project 2015-09 standard drafting team. NERC commits to working with stakeholders and Commission staff during the Project 2015-09 standards development process to address the issues raised in the NOPR.

23. ERCOT comments that the existing Reliability Standards provide a consistent but flexible structure for IROL identification that provides maximum benefit to interconnected transmission network. ERCOT believes that the Reliability Standards should continue to permit regional variations that will encourage flexibility for consideration of system-specific topology and characteristics as well as the application of operational experience and engineering judgment. ERCOT states that regional differences exist in terms of the specific processes and methodologies utilized to identify IROLs. However, according to ERCOT, appropriate consistency in IROL identification

[21] *See also* Peak Comments at 4-5. Peak points to Reliability Standards FAC-011-2 and FAC-014-2 as support for regional variation in establishing IROLs.

is driven by the definition of an IROL, the Reliability Standards associated with the identification of SOLs, and the communication and coordination among responsible entities. Further, ERCOT argues that allowing regional IROL differences benefits the bulk electric system by allowing the entities with the most operating experience to recognize the topology and operating characteristics of their areas, and to incorporate their experience and judgment into IROL identification.

24. Peak supports allowing regions to vary in their interpretation and identification of IROLs based on the level of risk determined by that region, as long as that interpretation is transparent and consistent within that region. Peak understands the definition of IROL to recognize regional differences and variances in the formulation of IROLs. Peak contends that such regional variation is necessary due to certain physical system differences. Thus, according to Peak, a consistent approach from region to region is not required, and may not enhance the overall reliability of the system. Peak explains that, in the Western United States, the evaluation of operating limits and stability must take into account the long transmission lines and greater distance between population centers, a situation quite different than the dense, interwoven systems found in much of the Eastern Interconnection. Peak adds that the Western Interconnection more frequently encounters localized instability because of the sparsity of the transmission system and the numerous small load centers supplied by few transmission lines, and these localized instances of instability have little to no impact on the overall reliability of the bulk electric system. Peak encourages the Commission to recognize that differences among the regions may

require flexibility to determine, through its SOL methodology, the extent and severity of instability and cascading that warrant the establishment of an IROL.

25. While Peak supports retaining the flexibility of a region by region application of the IROL definition, Peak notes that the current definition is not without some confusing ambiguity in the application of IROL that should be addressed, including ambiguity and confusion around the term "instability," the phrase "that adversely impact the reliability of the Bulk Electric System" and "cascading." Peak suggests that one method to eliminate confusion on the definition and application of IROLs would be to expand NERC's whitepaper to address concerns more specific to IROLs. Peak contends that further guidance from NERC in the whitepaper may remedy the confusion on the limits on the application of IROLs for widespread versus localized instability.

26. Peak requests that, if the Commission or NERC determines that a one-size-fits all approach is necessary for the identification of IROLs and eliminates the current flexibility for regional differences, that the Commission recognizes the limitations this will place on reliability coordinators to evaluate the specific conditions within their reliability coordinator area. The Commission should require that any standardized application of the IROL definition would need to address specific thresholds and implementation triggers for IROLs based on the risk profile and challenges facing specific regions, to avoid the downfalls of inaccurate or overbroad application, as discussed above.

Commission Determination

27. While it appears that regional discrepancies exist regarding the manner for calculating IROLs, we accept NERC's explanation that this issue is more appropriately addressed in NERC's Facilities Design, Connections and Maintenance or "FAC" Reliability Standards. NERC indicates that an ongoing FAC-related standards development project - NERC Project 2015-09 (Establish and Communicate System Operating Limits) - will address the development and identification of SOLs and IROLs. We conclude that NERC's explanation, that the Project 2015-09 standard drafting team will address the clarity and consistency of the requirements for establishing both SOLs and IROLs, is reasonable. Therefore, we will not direct further action on IROLs in the immediate TOP and IRO standard-related rulemaking. However, when this issue is considered in Project 2015-19, the specific regional difference of WECC's 1,000 MW threshold in IROLs should be evaluated in light of the Commission's directive in Order No. 802 (approving Reliability Standard CIP-014) to eliminate or clarify the "widespread" qualifier on "instability" as well as our statement in the Remand NOPR that "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability."[22]

[22] *Physical Security Reliability Standard*, Order No. 802, 149 FERC ¶ 61,140 (2014) and Remand NOPR, 145 FERC ¶ 61,158 at P 52. *See also* FPA section 215(a)(4) defining Reliable Operation as "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of

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B. Monitoring of Non-Bulk Electric System Facilities

NOPR

28. In the NOPR the Commission proposed to find that the proposed Reliability Standards adequately address the 2011 Southwest Outage Blackout Report recommendation regarding monitoring sub-100 kV facilities, primarily because of the responsibility of the reliability coordinator under proposed Reliability Standard IRO-002-4, Requirement R3 to monitor non-bulk electric system facilities to the extent necessary. The Commission noted, however, that "the transmission operator may have a more granular perspective than the reliability coordinator of its necessary non-bulk electric system facilities to monitor," and it is not clear whether or how the transmission operator would provide information to the reliability coordinator regarding which non-BES facilities should be monitored.[23] The Commission sought comment on how NERC will ensure that the reliability coordinator will receive such information.

29. The Commission stated that including such non-bulk electric system facilities in the definition of bulk electric system through the NERC Rules of Procedure exception process could be an option to address any potential gaps for monitoring facilities but notes that there may be potential efficiencies gained by using a more expedited method to include non-bulk electric system facilities that requires monitoring. The Commission

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a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

[23] NOPR, 151 FERC ¶ 61,236 at P 58.

sought comment on whether the BES exception process should be used exclusively in all cases. Alternatively, the Commission sought comment on whether this concern can be addressed through a review process of the transmission operators' systems to determine if there are important non-bulk electric system facilities that require monitoring.

Comments

30. Nearly all commenters support the Reliability Standards as proposed as sufficient for identifying and monitoring non-bulk electric system facilities, and do not support the alternatives offered by the Commission in the NOPR.[24] NERC submits that the proposed data specification and collection Reliability Standards IRO-010-2 and TOP-003-3, in addition to the exceptions process will help ensure that the reliability coordinator can work with transmission operators, and other functional entities, to obtain sufficient information to identify the necessary non-bulk electric system facilities to monitor. In support, NERC points to Reliability Standard IRO-010-2, which provides a mechanism for the reliability coordinator to obtain the information and data it needs for reliable operations and to help prevent instability, uncontrolled separation, or cascading outages. Further, NERC cites Reliability Standard TOP-003-3, which allows transmission operators to obtain data on non-bulk electric system facilities, necessary to perform their operational planning analyses, real-time monitoring, and real-time assessments from applicable entities. NERC explains that any data that the transmission operator obtains

[24] *E.g.* NERC, EEI, TAPS, Occidental, and NIPSCO.

regarding non-bulk electric system facilities under Reliability Standard TOP-003-3 can be passed on to the reliability coordinator pursuant to a request under proposed Reliability Standard IRO-010-2. Accordingly, NERC states that it would be premature to develop an alternative process before the data specification and bulk electric system exception process are allowed to work.

31. EEI states that this issue has been thoroughly studied by NERC through Project 2010-17 Phase 2 (Revisions to the Definition of Bulk Electric System) that led to modification of the definition of bulk electric system. EEI believes that the current process provides all of the necessary tools and processes to ensure that insights by TOPs are fully captured and integrated into existing monitoring systems that would ensure that all non-BES elements that might impact BES reliability are fully monitored. EEI does not support the alternative process proposed by the Commission. EEI warns that an alternative, parallel review process of the transmission operators' systems to determine if there are important non-bulk electric system facilities that require monitoring would either circumvent the revised bulk electric system definition process or arbitrarily impose NERC requirements (i.e., monitoring) onto non-bulk electric system elements.

32. APS agrees with the Commission that there would be a reliability benefit for the reliability coordinator to be able to identify facilities within the transmission operators' areas that may have a material impact on reliability. APS believes this benefit can be achieved using the method deployed in the Western Interconnection by the Western Electricity Coordinating Council (WECC). APS explains that the WECC planning coordination committee has published a bulk electric system inclusion guideline that

categorizes non-bulk electric system facilities that are to be identified by each planning authority and transmission planner when performing their system planning and operations reliability assessments, and the identified facilities are then reported to NERC. APS proposes a similar exception process be used in all cases. According to APS, each reliability coordinator would publish a guideline on how to identify non-bulk electric system facilities critical to reliability appropriate for their reliability coordinator area, and each planning coordinator and transmission planner would run studies according to the reliability coordinator guideline at least once every three years.

33. ERCOT states that performance of sufficient studies and evaluations of reliability coordinator areas occurs in cooperation and coordination with associated transmission operators, rending an additional review process unnecessary. However, to avoid any potential gaps in monitoring non-bulk electric system facilities and ensure that existing agreements and monitoring processes are respected, ERCOT states that the Commission should direct NERC to modify the TOP and IRO Reliability Standards to refer not only to sub-100 kV facilities identified as part of the bulk electric system through the Rules of Procedure exception process, but also to other sub-100 kV facilities as requested or agreed by the responsible entities.[25] ERCOT also states that because "non-bulk electric system facilities" fall outside the scope of the NERC Reliability Standards, use of this terminology should be avoided. ERCOT advocates for the Commission to permit

[25] *See also* ISO/RTOs Comments at 3.

monitoring of other sub-100 kV facilities to be undertaken as agreed to between the reliability coordinator and the transmission operator. ERCOT and ISO/RTOs suggest that the phrase "non-BES facilities" in Reliability Standard IRO-002-4, Requirement R3 should be replaced with "sub-100 kV facilities identified as part of the BES through the BES exception process or as otherwise agreed to between the Reliability Coordinator and Transmission Operator" and the phrase "non-BES data" in Reliability Standards IRO-010-2 (Requirement R1.1) and TOP-003-3 (Requirement R1.1) should be replaced with "data from sub-100 kV facilities identified as part of the BES through the BES exception process, as otherwise requested by the Responsible Entity, or as agreed to between the Transmission Operator and the Responsible Entity."[26]

34. ITC does not support the Commission's proposal. ITC states that transmission operators are required to incorporate any non-bulk electric system data into operational planning analysis and real-time assessments and monitoring, which therefore requires transmission operators to regularly review their models to identify impacting non-bulk electric system facilities. Conversely, ITC explains that conducting a one-time or periodic review and analysis of a transmission operator's model ignores the fact that changes in system conditions can cause the list of impacting non-bulk electric system facilities to change frequently.

[26] *See also* ISO/RTOs Comments at 4-6.

Commission Determination

35. We agree with NERC, TAPS, and EEI that the BES exception process can be a mechanism for identifying non-BES facilities to be included in the BES definition.[27] Indeed, *once* a non-BES facility is included in the BES definition under the BES exception process, the "non-BES facility" becomes a BES "Facility" under TOP-001-3, Requirement R10, and real-time monitoring is required of "Facilities."[28] However, we are concerned that in some instances the absence of real-time monitoring of non-BES facilities by the transmission operator within and outside its TOP area as necessary for determining SOL exceedances in proposed TOP-001-3, Requirement R10 creates a reliability gap. As the 2011 Southwest Outage Report indicates, the Regional Entity "should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and *actively monitored* and alarmed in

[27] NERC TOP/IRO Petition, Exh. G at 9 states in response to the 2011 Southwest Outage Recommendation #17, "If a non-BES facility impacts the BES, such as by contributing to an SOL or IROL, then the SDT expects that facility to be incorporated into the BES through the official BES Exception Process and it would be covered in proposed TOP-001-3, Requirement R10, Parts 10.1 and 10.2 by use of the defined term 'Facilities.'"

[28] NERC Glossary of Terms defines Facility as: "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.)"

[real-time contingency analysis] systems."[29] Such monitoring of non-BES facilities could provide a "stop gap" during the period where a sub-100 kV facility undergoes analysis as a possible BES facility, allowing for monitoring in the interim until such time the non-bulk electric system facilities become "BES Facilities" or the transmission operator determines that a non-bulk electric system facility is no longer needed for monitoring to determine a system operating limit exceedance in its area.[30] We believe that the operational planning analyses and real-time assessments performed by the transmission operators as well as the reliability coordinators will serve as the basis for determining which "non-BES facilities" require monitoring to determine system operating limit and interconnection reliability operating limit exceedances. In addition, we believe that monitoring of certain non-BES facilities that are occasional system operating limit exceedance performers may not qualify as a candidate for inclusion in the

[29] NOPR, 151 FERC ¶ 61,236 at P 55, citing Recommendation 17 of the 2011 Southwest Outage Blackout Report (emphasis added).

[30] NERC's BES Frequently Asked Questions, Version 1.6, February 25, 2015, Section 5.6. "How long will the process take?" at page 14 states: "In general, assuming a complete application, no appeals, and taking the allotted time for each subtask, the process could take up to 11.5 months, but is anticipated to be shorter for less complicated Exception Requests. If the Exception Request is appealed to the NERC Board of Trustees Compliance Committee pursuant to Section 1703 of the NERC Rules of Procedure, the process could take an additional 8.5 months, totaling 20 months. This does not include timing related to an appeal to the applicable legal authority or Applicable Governmental Authority. A Regional Entity, upon consultation with NERC, may extend the time frame of the substantive review process…." http://www.nerc.com/pa/RAPA/BES%20DL/BES%20FAQs.pdf.

BES definition, yet should be monitored for reliability purposes.[31] Accordingly, pursuant to section 215(d)(5) of the FPA, we direct NERC to revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities. We believe this is best accomplished by adopting language similar to Reliability Standard IRO-002-4, Requirement R3, which requires reliability coordinators to monitor non-bulk electric system facilities to the extent necessary. NERC can develop an equally efficient and effective alternative that addresses our concerns.[32]

36. To be clear, we are not directing that all current "non-BES" facilities that a transmission operator considers worthy of monitoring also be included in the bulk electric system. We believe that such monitoring may result in some facilities becoming part of the bulk electric system through the exception process; however it is conceivable that others may remain non-BES because they are occasional system operating limit exceedance performers that may not qualify as a candidate for inclusion in the BES definition.

[31] *See, e.g.*, NERC TOP/IRO Petition at 18 and 27-28.

[32] Reliability Standard IRO-002-4, Requirement R3 states: Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.

C. Removal of Load-Serving Entity Function from TOP-001-3

NOPR

37. NERC proposed the removal of the load-serving entity function from proposed Reliability Standard, TOP-001-3, Requirements R3 through R6, as a recipient of an operating instruction from a transmission operator or balancing authority. NERC supplemented its initial petition with additional explanation for the removal of the load-serving entity function from proposed Reliability Standard TOP-001-3.[33] NERC explained that the proposed standard gives transmission operators and balancing authorities the authority to direct the actions of certain other functional entities by issuing an operating instruction to maintain reliability during real-time operations.

38. In the NOPR, the Commission noted that NERC was required to make a compliance filing in Docket No. RR15-4-000, regarding NERC's Risk-Based Registration initiative, and that the Commission's decision on that filing will guide any action in this proceeding. On March 19, 2015, the Commission approved, in part, NERC's Risk-Based Registration initiative, but denied, without prejudice, NERC's proposal to eliminate the load-serving entity function from the registry process, finding that NERC had not adequately justified its proposal.[34] In doing so, the Commission

[33] The Commission also notes that Reliability Standards TOP-003-3 and IRO-010-2 also include "load-serving entity" as an applicable entity.

[34] *North American Electric Reliability Corp.* 150 FERC ¶ 61,213 (2015) (March 19 Order).

directed NERC to provide additional information to support this aspect of its proposal to address the Commission's concerns. On July 17, 2015, NERC submitted a compliance filing in response to the March 19 Order.

Comments

39. NERC states that while load-serving entities play a role in facilitating interruptible (or voluntary) load curtailments, that role is to simply communicate requests for voluntary load curtailments and does not necessitate requiring load-serving entities to comply with a transmission operator's or balancing authority's operating instructions issued pursuant to Reliability Standard TOP-001-3. In short, the load-serving entity's role in carrying out interruptible load curtailment is not the type of activity that rises to the level of requiring an operating instruction. EEI and TAPS contend it is appropriate to omit the load-serving entity function from TOP-001-3 applicability. TAPS explains that because the load-serving entity function does not own or operate equipment, the load-serving entity function cannot curtail load or perform other corrective actions subject to reliability standards. Dominion asserts that a load-serving entity does not own or operate bulk electric system facilities or equipment or the facilities or equipment used to serve end-use customers and is not aware of any entity, registered solely as a load-serving entity, which is responsible for operating one or more elements or facilities.

Commission Determination

40. In an October 15, 2015 order in Docket No. RR15-4-001, the Commission accepted a NERC compliance filing, finding that NERC complied with the March 17 Order with respect to providing additional information justifying the removal of the load-

serving entity function.[35] The Commission also found that NERC addressed the concerns expressed regarding an accurate estimate of the load-serving entities to be deregistered and the reliability impact of doing so, and how load data will continue to be available and reliability activities will continue to be performed even after load-serving entities would no longer be registered.[36] Because the load-serving entity category is no longer a NERC registration function, no further action is required in this proceeding.[37]

D. Data Exchange Capabilities

41. The Commission approved Reliability Standards COM-001-2 (Communications) and COM-002-4 (Operating Personnel Communications Protocols) in Order No. 808, and noted that in the NOPR underlying that order (COM NOPR) it had raised concerns as to whether Reliability Standard COM-001-2 addresses facilities that directly exchange or transfer data.[38] In response to that concern in the COM NOPR, NERC clarified that Reliability Standard COM-001-2 did not need to include requirements regarding data exchange capability because such capability is covered under other existing and proposed

[35] *North American Electric Reliability Corp*, 153 FERC ¶ 61,024 (2015).

[36] *Id.*

[37] In its response to comments in Docket No. RR15-4-000, NERC stated that, once the Commission approved the proposed deactivation of the load-serving entity registration function, it would make any needed changes to the Reliability Standards through the Reliability Standard Development Process. *See* January 26, 2016, NERC Motion to File Limited Answer at 6 in Docket No. RR15-4-000.

[38] *See* NOPR, 151 FERC ¶ 61,236 at P 67, citing *Communications Reliability Standards*, Order No. 808, 151 FERC ¶ 61,039 (2015).

standards. Based on that explanation, the Commission decided not to make any determinations in Order No. 808 and stated that it would address the issue in this TOP and IRO rulemaking proceeding.[39]

NOPR

42. In the NOPR, the Commission stated that facilities for data exchange capabilities appear to be addressed in NERC's TOP/IRO petition. However, the Commission sought additional explanation from NERC regarding how it addresses data exchange capabilities in the TOP and IRO Standards in the following areas: (a) redundancy and diverse routing; and (b) testing of the alternate or less frequently used data exchange capability.

1. Redundancy and Diverse Routing of Data Exchange Capabilities

NOPR

43. In the NOPR, the Commission agreed that proposed Reliability Standard TOP-001-3, Requirements R19 and R20 require some form of "data exchange capabilities" for the transmission operator and balancing authority and that proposed Reliability Standard TOP-003-3 addresses the operational data itself needed by the transmission operator and balancing authority. In addition, the Commission agreed that Reliability Standard IRO-002-4, Requirement R1 requires "data exchange capabilities" for the reliability coordinator and that proposed Reliability Standard IRO-010-2 addresses the operational data needed by the reliability coordinator and that proposed Reliability Standard IRO-

[39] *Id.* citing Order No. 808, 151 FERC ¶ 61,039 at P 54.

002-4 Requirement R4 requires a redundant infrastructure for system monitoring. However, the Commission was concerned that it is not clear whether redundancy and diverse routing of data exchange capabilities were adequately addressed in proposed Reliability Standards TOP-001-3 and IRO-002-4 for the reliability coordinator, transmission operator, and balancing authority and sought explanation or clarification on how the standards address redundancy and diverse routing or an equally effective alternative. The Commission also stated that, if NERC or others believe that redundancy and diverse routing are not addressed, they should address whether there are associated reliability risks of the interconnected transmission network for any failure of data exchange capabilities that are not redundant and diversely routed.

Comments

44. NERC and EEI state that the requirements in the TOP and IRO Reliability Standards covering data exchange are results-based, articulating a performance objective without dictating the manner in which it is met. NERC adds that, in connection with their compliance monitoring activities, NERC and the Regional Entities will review whether applicable entities have met that objective, and will consider whether the applicable entity has redundancy and diverse routing, and whether the applicable entity tests these capabilities. EEI also argues that Reliability Standard EOP-008-1, Requirements R1, R1.2, R1.2.2, R7, and EOP-001-2.1b, Requirements R6 and R6.1 provide specific requirements for maintaining or specifying reliable back-up data exchange capability necessary to ensure BES Reliability and the testing of those capabilities.

45. ERCOT asserts that the Reliability Standards already appropriately provide for redundancy and diversity of routing of data exchange capabilities, as both the existing and proposed standards either explicitly or implicitly require responsible entities to ensure availability of data and data exchange capabilities. ERCOT states that, should the Commission seek to provide further clarification on this issue, such clarification should be consistent with existing explicit requirements regarding the redundancy of data exchange capabilities, such as Requirement R4 of Reliability Standard IRO-002-4.

46. ISOs/RTOs and ERCOT explain the suite of currently-effective standards and the proposed TOP and IRO standards establish performance-based requirements for reliability coordinators, balancing authorities, and transmission operators, that create the need for those entities to have diverse and redundantly routed data communication systems. In the event of a failure of data communications, ISOs/RTOs explain that the functional entity should be able to rely on the redundant and diversely routed voice capabilities required in the COM standards.

Commission Determination

47. We agree with NERC and other commenters that there is a reliability need for the reliability coordinator, transmission operator and balancing authority to have data exchange capabilities that are redundant and diversely routed. However, we are concerned that the TOP and IRO Standards do not clearly address redundancy and diverse routing so that registered entities will unambiguously recognize that they have an obligation to address redundancy and diverse routing as part of their TOP and IRO compliance obligations. NERC's comprehensive approach to establishing

communications capabilities necessary to maintain reliability in the COM standards is applicable to data exchange capabilities at issue here.[40] Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing. In addition, we direct NERC to clarify that "redundant infrastructure" for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.

48. Further, we disagree with commenter arguments that Reliability Standard EOP-008-1 provides alternatives to data exchange redundancy and diverse routing. The NERC standard drafting team that developed the COM standards addressed this issue in the standards development process, responding to a commenter seeking clarification on the relationship between communication capabilities, alternative communication capabilities, primary control center functionality and backup control center functionality. The standard drafting team responded that "Interpersonal Communication and Alternative Interpersonal Communication are not related to EOP-008," even though Reliability

[40] *See, e.g*, Order No. 808, 151 FERC ¶ 61,039 at P 8: "NERC stated in its [COM] petition that Reliability Standard COM-001-2 establishes requirements for Interpersonal Communication capabilities necessary to maintain reliability. NERC explained that proposed Reliability Standard COM-001-2 applies to reliability coordinators, balancing authorities, transmission operators, generator operators, and distribution providers. The proposed Reliability Standard includes eleven requirements and two new defined terms, "Interpersonal Communication" and "Alternative Interpersonal Communication," that, according to NERC, collectively provide a comprehensive approach to establishing communications capabilities necessary to maintain reliability."

Standard EOP-008-1 Requirement R1 applies equally to data communications and voice communications.[41] To the extent the standard drafting team asserted that Reliability Standard EOP-008 did not supplant the redundancy requirements of the COM Reliability Standards, we believe the same is true for data communications. Redundancy for data communications is no less important than the redundancy explicitly required in the COM standards for voice communications.

2. Testing of the Alternate or Less Frequently Used Data Exchange Capability

NOPR

49. In the NOPR, the Commission expressed concern that the proposed TOP and IRO Reliability Standards do not appear to address testing requirements for alternative or less frequently used mediums for data exchange to ensure they would properly function in the event that the primary or more frequently used data exchange capabilities failed. Accordingly, the Commission sought comment on whether and how the TOP and IRO Reliability Standards address the testing of alternative or less frequently used data exchange capabilities for the transmission operator, balancing authority and reliability coordinator.

[41] *See* NERC COM Petition, Exh. M, (Consideration of Comments on Initial Ballot, February 25 - March 7, 2011) at 30 (emphasis added).

Comments

50. Commenters assert that the existing standards have sufficient testing requirements. NERC points to Reliability Standard EOP-008-1, Requirement R7, which requires that applicable entities conduct annual tests of their operating plan that demonstrates, among other things, backup functionality. Similarly, EEI cites EOP-008-1 Requirements R1, R1.2, R1.2.2, R7 and EOP-001-2.1b Requirements R6 and R6.1 as providing specific requirements for maintaining and testing of data exchange capabilities. ITC suggests that NERC's proposed Standard TOP-001-3 provides ample assurance that the data exchange capabilities are regularly tested and also points to Reliability Standards EOP-001-2.1b and EOP-008-1 which require entities, including those covered by TOP-001-3, to maintain reliable back-up data exchange capability as necessary to ensure reliable BES operations, and require that such capabilities be thoroughly and regularly tested.

Commission Determination

51. We agree with NERC and other commenters that there is a reliability need for the reliability coordinator, transmission operator and balancing authority to test alternate data exchange capabilities. However, we are not persuaded by the commenters' assertions that the need to test is implied in the TOP and IRO Standards. Rather, we determine that testing of alternative data exchange capabilities is important to reliability and should not be left to what may or may not be implied in the standards.[42] Therefore, pursuant to

[42] In NERC's COM Petition, Exh. M, (Consideration of Comments, Index to Questions, Comments and Responses) at 35, the standard drafting team stated that the

(continued ...)

section 215(d)(5) of the FPA, we direct NERC to develop a modification to the TOP and IRO standards that addresses a data exchange capability testing framework for the data exchange capabilities used in the primary control centers to test the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority. We believe that the structure of Reliability Standard COM-001-2, Requirement R9 could be a model for use in the TOP and IRO Standards.[43]

E. Other Issues Raised by Commenters

1. Emergencies and Emergency Assistance Under Reliability Standard TOP-001-3

52. Reliability Standard TOP-001-3, Requirement R7 requires each transmission operator to 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. NIPSCO contends that this requirement limits the ability of an adjacent transmission operator that is located along the seam in another reliability coordinator area from rendering assistance in an emergency because Requirement R7 only requires each transmission operator to assist other transmission

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"requirement [COM-001-2, Requirement R9 which addresses testing of alternative interpersonal communication] applies to the primary control center" and "EOP-008 applies to the back up control center."

[43] COM-001-2, Requirement R9 states: "Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours."

operators within its reliability coordinator area. NIPSCO points to Reliability Standard IRO-014-3, Requirement R7 which requires each reliability coordinator to assist other reliability coordinators and, according to NIPSCO, a similar requirement in Reliability Standard TOP-001-3 will make the two sets of requirements consistent with each other.

53. In addition, Reliability Standard TOP-001-3, Requirement R8 states:

> 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.

BPA contends that the phrase "could result in" in Requirement R8 of TOP-001-3 is overly broad and suggests corrective language underscored below:

> 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 an Emergency, or could result in an Emergency <u>if a credible Contingency were to occur</u>.

As an alternative to changing the language of the requirement, BPA asks the Commission to clarify that it is in the transmission operator's discretion to determine what "could result" in an emergency, based on the transmission operator's experience and judgment.

<u>Commission Determination</u>

54. With regard to NIPSCO's concern, we do not believe that the requirements as written limit the ability of an adjacent transmission operator located along the seam in another reliability coordinator area from rendering assistance in an emergency. We agree with NIPSCO that proposed Reliability Standard TOP-001-3, Requirement R7 requires

each transmission operator to assist other transmission operators within its reliability coordinator area and further agree with NIPSCO that proposed Reliability Standard IRO-014-3, Requirement R7 requires each reliability coordinator to assist other reliability coordinators.[44] In addition, we understand that an adjacent transmission operator in another reliability coordinator area can render assistance when directed to do so by its own reliability coordinator.[45] Having a similar requirement in Reliability Standard TOP-001-3 compared to Reliability Standard IRO-014-3, Requirement R7 is unnecessary and could complicate the clear decision-making authority NERC developed in the TOP and IRO Reliability Standards. Thus, we determine that no further action is required.

55. With regard to clarification of emergencies in Reliability Standard TOP-001-3, Requirement R8, we do not see a need to modify the language as suggested by BPA. The requirement as written implies that the transmission operator has discretion to determine what could result in an emergency, based on its experience and judgment. In addition, we note that the transmission operators' required next-day operational planning analysis, real-time assessments and real-time monitoring under the TOP Reliability Standards provide evaluation, assessment and input in determining what "could result" in an emergency.

[44] *See* Reliability Standards TOP-001-3 and IRO-014-3.

[45] *See* Reliability Standard IRO-001-4, Requirement R2.

2. Reliability Coordinator Authority in Next-Day Operating Plans

56. Reliability Standard TOP-002-4, Requirements R2 and R4 require transmission operators and balancing authorities to have operating plans. Reliability Standard TOP-002-4, Requirements R6 and R7 require transmission operators and balancing authorities to provide their operating plans to their reliability coordinators and Reliability Standard IRO-008-2, Requirement R2 requires reliability coordinators to develop a coordinated operating plan that considers the operating plans provided by the transmission operators and balancing authorities.

57. NIPSCO is concerned about the absence of any required direct coordination between transmission operators and balancing authorities as well as the absence of any guidance regarding the resolution of potential conflicts between the transmission operator and balancing authority operating plans. NIPSCO contends that the Reliability Standards provide only a limited coordination process in which reliability coordinators are required to notify those entities identified with its coordinated operating plan of their roles. NIPSCO argues that there is no provision for modifications to operating plans based on the reliability coordinator's coordinated operating plan or based on potential conflicts between the transmission operator and balancing authority operating plans. NIPSCO is concerned that a potential disconnect between operating plans could lead to confusion or a failure of coordination of reliable operations.

Commission Determination

58. We believe that proposed Reliability Standards TOP-002-4 and IRO-008-2 along with NERC's definition of reliability coordinator address NIPSCO's concern.[46] Although the transmission operator and balancing authority develop their own operating plans for next-day operations, both the transmission operator and balancing authority notify entities identified in the operating plans as to their role in those plans. Further, each transmission operator and balancing authority must provide its operating plan for next-day operations to its reliability coordinator.[47] In Reliability Standard IRO-008-2, Requirement R2, the reliability coordinator must have a coordinated operating plan for next-day operations to address potential SOL and IROL exceedances while considering the operating plans for the next-day provided by its transmission operators and balancing authorities. Also, Reliability Standard IRO-008-2, Requirement R3 requires that the reliability coordinator notify impacted entities identified in its operating plan as to their role in such plan. Based on the notification and coordination processes of Reliability Standards TOP-002-4 (for the transmission operator and balancing authority) and IRO-

[46] NERC Glossary of Terms defines the Reliability Coordinator as "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."

[47] Reliability Standard TOP-002-4 (Operations Planning).

008-2 (for the reliability coordinator) for next-day operating plans, as well as the fact that the reliability coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the bulk electric system, we believe that the reliability coordinator has the authority and necessary next-day operational information to resolve any next-day operational issues within its reliability coordinator area. Accordingly, we deny NIPSCO's request.

3. Reliability Coordinator Authority in Next-Day Operations and the Issuance of Operating Instructions

59. NIPSCO is concerned with the elimination of the explicit requirement in currently-effective Reliability Standard IRO-004-2 that each transmission operator, balancing authority, and transmission provider comply with the directives of a reliability coordinator based on next-day assessment in the same manner as would be required in real-time operating conditions. NIPSCO claims that, while the Reliability Standards appear to address the Commission's concerns regarding directives issued in other than emergency conditions through the integration of the term "operating instruction," the standards only allow for the issuance of directives in real-time. NIPSCO points to Reliability Standard TOP-001-3, Requirements R1 and R2, and IRO-001-4, Requirement R1, where transmission operators, balancing authorities, and reliability coordinators are explicitly given authority and responsibility to issue operating instructions to address reliability in their respective areas. NIPSCO states that "operating instruction" is "clearly limited to real-time operations" as it underscored below:

> A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or

> preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)

NIPSCO contends that there are no clear requirements addressing potential conflicts between operating plans, no clear requirements authorizing the issuance of a directive to address issues identified in next-day planning, and no clear requirement to comply with any directive so issued. NIPSCO is concerned that this raises the possibility that potential next-day problems identified in the operational planning analyses may not get resolved in the next-day planning period because the reliability coordinator's authority to issue operating instructions is limited to real-time operation. According to NIPSCO, this limitation undermines some of the usefulness of the next-day planning and the performance of operational planning analyses.

Commission Determination

60. We do not share NIPSCO's concern. Rather, we believe that, because the reliability coordinator is required to have a coordinated operating plan for the next-day operations, the reliability coordinator will perform its task of developing a coordinated operating plan in good faith, with inputs not only from its transmission operators and balancing authorities, but also from its neighboring reliability coordinators.[48] A reliability coordinator has a wide-area view and bears the ultimate responsibility to

[48] *See* Reliability Standards IRO-008-2, Requirements R1 and R2, and IRO-014-3, Requirement R1.

maintain the reliability within its footprint, "including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations."[49]

61. In addition, we do not agree with NIPSCO's claim that operating instructions are "clearly limited to real-time operations." The phrase "real-time operation" in the definition of operating instruction as emphasized by NIPSCO applies to the entity that issues the operating instruction which is "operating personnel responsible for the Real-time operation." The definition of operating instruction is "[a] command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System…." In addition, the time horizons associated with the issuance of or compliance with an operating instruction are not found in the definition of operating instructions, but found in the individual requirement(s) applicable to issuing an operating instruction. For example, Reliability Standard TOP-001-3, Requirements R1 through R6 and IRO-001-4, Requirements R1 through R3 are all requirements associated with the issuance or compliance of operating instructions. In all nine requirements, the defined time horizon is "same-day operations" and "real-time operations."[50] Accordingly, we deny NIPSCO's request on this issue.

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[49] *See supra* n. 46.

[50] NERC's "Time Horizons" document defines "Same-Day Operations" time horizon as "routine actions required within the timeframe of a day, but not real-time" and defines "Real-Time Operations" time horizon as "actions required within one hour or less to preserve the reliability of the bulk electric system." *See* http://www.nerc.com/files/Time_Horizons.pdf.

4. Updating Operational Planning Analyses and Real-Time Assessments

62. NIPSCO is concerned that the proposed Reliability Standards are not clear as to whether updates or additional analyses are required. NIPSCO points to Reliability Standards IRO-008-2 and TOP-002-4, which require reliability coordinators to perform - and transmission operators and balancing authorities to have - an operational analysis for the next-day, but do not specify when such analysis must be performed or if it needs to be updated in next-day planning based on any change in inputs. Similarly, NIPSCO asserts that the proposed Reliability Standards require the performance of a real-time assessment every 30 minutes but do not address the need to potentially update operating plans based on changes in system conditions (including unplanned outages of protection system degradation) and do not require the performance of additional real-time assessments or other studies with more frequency based on changes in system conditions. NIPSCO explains that it is not clear if or when, based on the operational planning analysis results, some type of additional study or analysis would need to be undertaken prior to the development of an operating plan. According to NIPSCO, the text of the requirements and the definition do not specifically require additional studies; however, it seems that when issues associated with protection system degradation or outages are identified, further study of these issues would be required and/or additional analyses required to update results as protection system status or transmission or generation outages change.

Commission Determination

63. We do not share NIPSCO's concern. Reliability Standards IRO-008-2 and TOP-002-4 require reliability coordinators to perform and transmission operators to have an operational planning analysis to assess whether its planned operations for next-day will exceed any of its SOLs (for the transmission operator) and SOLs/IROLs (for the reliability coordinator). Both are required to have an operating plan(s) to address potential SOL and/or IROL exceedances based on its operational planning analysis results. We believe that, if the applicable inputs of the operational planning analysis change from one operating day to the next operating day, and because an operational planning analysis is an "evaluation of projected system conditions," a new operational planning analysis must be performed to include the change in applicable inputs. Based on the results of the new operational planning analysis for next-day, operating plans may need updating to reflect the results of the new operational planning analysis. Likewise with the real-time assessment, as system conditions change and the applicable inputs to the real-time assessment change, a new assessment would be needed to accurately reflect applicable inputs, as stated in the real-time assessment definition.[51]

[51] Real-time assessment is defined 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.)."

5. Performing a Real-time Assessment When Real-Time Contingency Analysis Is Unavailable

64. Reliability Standard TOP-001-3, Requirement R13 requires transmission operators to ensure a real-time assessment is performed at least every 30 minutes. NIPSCO states that NERC's definition of real-time assessment anticipates that real-time assessments must be performed through the use of either an internal tool or third-party service.[52] NIPSCO believes that compliance with the requirement to perform a real-time assessment should not be dependent on the availability of a system or tool. According to NIPSCO, if a transmission operators' tools are unavailable for 30 minutes or more, they should be permitted to meet the requirement to assess existing conditions through other means.

Commission Determination

65. Reliability Standard TOP-001-3, Requirement R13 requires the transmission operator to ensure the assessment is performed at least once every 30 minutes, but does not state that the transmission operator on its own must perform the assessment and does not specify a system or tool. This gives the transmission operator flexibility to perform its real-time assessment. Further supporting this flexibility, NERC's definition of real-time assessment states that a real-time assessment "may be provided through internal systems or through third-party services."[53] Therefore, we believe that Reliability

[52] *See supra* n. 48.

[53] NERC TOP/IRO Petition at 18.

Standard TOP-001-3, Requirement R13 does not specify the system or tool a transmission operator must use to perform a real-time assessment. In addition, NERC explains that Reliability Standard TOP-001-3, Requirement R13 and the definition of real-time assessment "do not specify the manner in which an assessment is performed nor do they preclude Reliability Coordinators and Transmission Operators from taking 'alternative actions' and developing procedures or off-normal processes to mitigate analysis tool (RTCA) outages and perform the required assessment of their systems. As an example, the Transmission Operator could rely on its Reliability Coordinator to perform a Real-time Assessment or even review its Reliability Coordinator's Contingency analysis results when its capabilities are unavailable and vice-versa."[54] Accordingly, we conclude that TOP-001-3 adequately addresses NIPSCO's concern, namely, if a transmission operators' tools are unavailable for 30 minutes or more, the transmission operator has the flexibility to meet the requirement to assess system conditions through other means.

6. Valid Operating Limits

66. IESO is concerned that the revised TOP standards do not compel an entity to verify existing limits or re-establish limits following an event that results in conditions not previously assessed within an acceptable time frame as is specified in the currently-

[54] NERC TOP/IRO Petition, Exh. K (Summary of Development History and Complete Record of Development), Consideration of Comments May 19, 2014 through July 2, 2014) at 61.

effective Reliability Standard TOP-004-2 Requirement R4.[55] IESO disagrees that this is sufficient because there is no requirement in the Reliability Standard TOP-001-3 standard to derive a new set of limits, particularly transient stability limits, or verify that an existing set of limits continue to be valid for the prevailing conditions within an established timeframe. IESO contends that a real-time assessment is useful only if the system conditions are assessed against a valid set of limits and is unable to verify or re-establish stability-restricted SOLs with which to assess system conditions to address reliability concerns. IESO believes that an explicit requirement to verify or re-establish SOLs when entering into an unstudied state must therefore be imposed to fill this reliability gap.

67. Further, IESO asserts that implementing operating plans to mitigate an SOL exceedance does not require transmission operators to determine a valid set of limits with which to compare the prevailing system conditions (i.e. whether or not the limits are exceeded). While the IESO supports performing a real-time assessment every 30 minutes, it asserts that performing an assessment without first validating the current set of limits or re-establishing a new set of limits as the boundary conditions leaves a reliability gap.

[55] Requirement R4 states: "If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes."

Commission Determination

68. We agree with IESO that valid operating limits, including transient stability limits, are essential to the reliable operation of the interconnected transmission network and that a transmission operator must not enter into an unknown operating state. Further, we agree with IESO that Reliability Standard TOP-001-3 has no requirements to derive a new set of limits or verify an existing set of limits for prevailing operating conditions within an established timeframe. However, IESO's concerns regarding the establishment of transient stability operating limits are addressed collectively through proposed Reliability Standard TOP-001-3, certain currently-effective Facilities Design, Connections, and Maintenance (FAC) Reliability Standards and NERC's Glossary of Terms definition of SOLs.

69. In its SOL White Paper, NERC stated that the intent of the SOL concept is to bring clarity and consistency for establishing SOLs, exceeding SOLs, and implementing operating plans to mitigate SOL exceedances.[56] In addition, "transient stability ratings"

[56] NERC Petition, Exh. E (White Paper on System Operating Limit Definition and Exceedance Clarification) at 1. NIPSCO requests clarification as to how NERC's SOL White Paper can be used in determining compliance. NIPSCO requests that any substantive content that is treated as containing enforceable compliance requirements be filed with the Commission for approval. NERC developed the SOL White Paper as a guidance document which provides links between relevant reliability standards and reliability concepts to establish a common understanding necessary for developing effective operating plans to mitigate SOL exceedances. Guidelines are illustrative but not mandatory and enforceable compliance requirements. *See, e.g. North American Electric Reliability Corp.*, 143 FERC ¶ 61,271, at P 15 (2013). Accordingly, we see no need for further revisions to the Reliability Standards to incorporate the SOL White Paper as requested by NIPSCO.

are included in the SOL definition. Further, in the SOL White Paper, NERC states that the "concept of SOL determination is not complete without looking at the approved NERC FAC standards FAC-008-3, FAC-011-2 and FAC-014-2."[57] Specific to IESO's concerns of establishing transient stability limits, we agree with NERC that approved Reliability Standard FAC-011-2, Requirement R2 requires that the reliability coordinator's SOL methodology include a requirement that SOLs provide a certain level of bulk electric system performance including among other things, that the "BES shall demonstrate transient, dynamic and voltage stability" and that "all Facilities shall be within their…stability limits" for both pre- and post-contingency conditions.[58] In addition, we note that currently-effective Reliability Standard FAC-011-2, Requirement R2.1 states that "[i]n the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall *reflect changes to system topology* such as Facility outages."[59]

70. With respect to Reliability Standard TOP-001-3, we agree with NERC that Requirement R13 specifies that transmission operators must perform a real-time assessment at least once every 30 minutes, which by definition is an evaluation of system conditions to assess existing and potential operating conditions. The real-time

[57] NERC Petition, Exh. E at 1.

[58] *Id*. at 2. *See also* Reliability Standard FAC-011-2, Requirement R2.

[59] Reliability Standard FAC-011-1, Requirement R2.1 (emphasis added).

assessment provides the transmission operator with the necessary knowledge of the system operating state to initiate an operating plan, as specified in Requirement R14, when necessary to mitigate an exceedance of SOLs. In addition, the SOL White Paper provides technical guidance for including timelines in the required operating plans to return the system to within prescribed ratings and limits.[60] Accordingly, we conclude that the establishment of transient stability operating limits is adequately addressed collectively through proposed Reliability Standard TOP-001-3, currently-effective Reliability Standards FAC-011-2 and FAC-014-2 and NERC's Glossary of Terms definition of SOLs.[61]

III. Information Collection Statement

71. The collection of information contained in this Final Rule is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[62] OMB's regulations require approval of certain informational collection requirements imposed by agency rules.[63] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be

[60] NERC Petition at 57-58.

[61] *See* Reliability Standard FAC-014-2, Requirement R2.

[62] 44 U.S.C. 3507(d) (2012).

[63] 5 C.F.R. § 1320.11.

penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

Public Reporting Burden: The number of respondents below is based on an estimate of the NERC compliance registry for the balancing authority, transmission operator, generator operator, distribution provider, generator owner, load-serving entity, purchasing-selling entity, transmission service provider, interchange authority, transmission owner, reliability coordinator, planning coordinator, and transmission planner functions. The Commission based its paperwork burden estimates on the NERC compliance registry as of May 15, 2015. According to the registry, there are 11 reliability coordinators, 99 balancing authorities, 450 distribution providers, 839 generator operators, 80 purchasing-selling entities, 446 load-serving entities, 886 generator owners, 320 transmission owners, 24 interchange authorities, 75 transmission service providers, 68 planning coordinators, 175 transmission planners and 171 transmission operators. The estimates are based on the change in burden from the current standards to the standards approved in this Final Rule. The following table illustrates the burden to be applied to the information collection:

RM15-16-000 (Transmission Operations Reliability Standards, Interconnection Reliability Operations and Coordination Reliability Standards)						
	Number of Respondents[64] (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[65] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
FERC-725A						
TOP-001-3	196 (TOP & BA)	1	196	96 hrs. $6,369	18,816 hrs., $1,248,441	96 hrs, $6,369
TOP-002-4	196 (TOP & BA)	1	196	284 hrs. $18,843	55,664 hrs., $3,693,306	284 hrs., $18,843
TOP-003-3	196 (TOP & BA)	1	196	230 hrs. $15,260	45,080 hrs., $2,991,058	230 hrs., $15,260
Sub-Total for FERC-725A					123,252 hrs., $7,932,806	
FERC-725Z						
IRO-001-4[66]	177 (RC & TOP)	1	177	0 hrs. $0	0 hrs. $0	0 hrs. $0
IRO-002-4	11 (RC)	1	11	24 hrs. $1,592	264 hrs., $17,516	24 hrs., $1,592
IRO-008-2	11 (RC)	1	11	228 hrs. $15,127	2,508 hrs., $166,405	228 hrs., $15,127
IRO-010-2	11 (RC)	1	11	36 hrs. $2,388	396 hrs., $26,274	36 hrs., $2,388
IRO-014-3	11 (RC)	1	11	12 hrs. $796	132 hrs., $8,758	12 hrs., $796
IRO-017-1	180 (RC, PC, & TP)	1	180	218 hrs. $14,464	39,240 hrs., $2,603,574	218 hrs., $14,464
Sub-Total for FERC-725Z					42,540 hrs., $2,822,529.00	

[64] The number of respondents is the number of entities for which a change in burden from the current standards to the proposed exists, not the total number of entities from the current or proposed standards that are applicable.

[65] The estimated hourly costs (salary plus benefits) are based on Bureau of Labor Statistics (BLS) information, as of April 1, 2015, for an electrical engineer ($66.35/hour). These figures are *available at* http://bls.gov/oes/current/naics3_221000.htm#17-0000.

[66] IRO-001-4 is a revised standard with no increase in burden.

Retirement of current standards currently in FERC-725A	457(RC, TOP, BA, TSP, LSE, PSE, & IA)	1	457	-223 hrs. -$14,796	-101,911 hrs., -$6,761,794	-223 hrs. -$14,796
NET TOTAL of NOPR in RM15-16					**63,881 hrs, $3,993,540**	

Title: FERC-725Z, Mandatory Reliability Standards: IRO Reliability Standards, and FERC-725A, Mandatory Reliability Standards for the Bulk-Power System.

Action: Proposed Changes to Collections.

OMB Control Nos: 1902-0276 (FERC-725Z); 1902-0244 (FERC-725A).

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: On-going.

72. Necessity of the Information and Internal review: The Commission has reviewed the requirements of 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, and IRO-017-1 and made a determination that the standards are necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

73. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

74. Comments on the requirements of this rule may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk

Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference OMB Control Nos. 1902-0276 (FERC-725Z) and 1902-0244 (FERC-725A)) in your submission.

IV. Environmental Analysis

75. 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.[67] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[68] The actions approved herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Analysis

76. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of Proposed Rules that will have significant economic impact on a substantial number of small entities. [69] The Small Business Administration's (SBA) Office of Size

[67] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[68] 18 C.F.R. 380.4(a)(2)(ii).

[69] 5 U.S.C. 601-12.

Standards develops the numerical definition of a small business.[70] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from a standard based on megawatt hours).[71] 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, and IRO-017-1 are expected to impose an additional burden on 196 entities (reliability coordinators, transmission operators, balancing authorities, transmission service providers, and planning authorities). Comparison of the applicable entities with the Commission's small business data indicates that approximately 82 of these entities are small entities that will be affected by the proposed Reliability Standards.[72] As discussed above, 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, and IRO-017-1 will serve to enhance reliability by imposing mandatory requirements for operations planning, system monitoring, real-time actions, coordination between applicable entities, and operational reliability data. The Commission estimates that each of the small entities to whom the proposed Reliability Standards TOP-001-3, TOP-002-4,

[70] 13 C.F.R. 121.101.

[71] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77343 (Dec. 23, 2013).

[72] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 750 employee threshold for each affected entity to conduct a comprehensive analysis.

TOP-003-3, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, and IRO-017-1 applies will incur costs of approximately $147,364 (annual ongoing) per entity. The Commission does not consider the estimated costs to have a significant economic impact on a substantial number of small entities.

VI. Document Availability

77. 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 FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

78. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

79. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

VII. Effective Date and Congressional Notification

80. This final rule is effective **[insert date 60 days from publication in 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.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

153 FERC ¶ 61,228
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000
Order No. 818]

Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards

(Issued November 19, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Commission approves Reliability Standards and definitions of terms submitted in three related petitions by the North American Electric Reliability Corporation (NERC), the Commission-approved Electric Reliability Organization. The Commission approves Reliability Standards EOP-011-1 (Emergency Operations) and PRC-010-1 (Undervoltage Load Shedding). The proposed Reliability Standards consolidate, streamline and clarify the existing requirements of certain currently-effective Emergency Preparedness and Operations (EOP) and Protection and Control (PRC) standards. The Commission also approves NERC's revised definition of the term Remedial Action Scheme as set forth in the NERC Glossary of Terms Used in Reliability Standards, and modifications of specified Reliability Standards to incorporate the revised definition. Further, the Commission approves the implementation plans, and the retirement of certain currently-effective Reliability Standards.

EFFECTIVE DATES: This rule will become effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].**

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SUPPLEMENTARY INFORMATION:

153 FERC ¶ 61,228
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Revisions to Emergency Operations Reliability Standards	Docket Nos.	RM15-7-000
Revisions to Undervoltage Load Shedding Reliability Standards		RM15-12-000
Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards		RM15-13-000

ORDER NO. 818

FINAL RULE

(Issued November 19, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves Reliability Standards and definitions of terms submitted in three related petitions by the North American Electric Reliability Corporation (NERC), the Commission-approved Electric Reliability Organization (ERO). In particular, the Commission approves Reliability Standards EOP-011-1 (Emergency Operations) and PRC-010-1 (Undervoltage Load Shedding). The Commission finds that the Reliability Standards consolidate, streamline, and clarify the existing requirements of several

[1] 16 U.S.C. 824o.

currently-effective Emergency Preparedness and Operations (EOP) and Protection and Control (PRC) standards, and address certain Commission directives set forth in Order No. 693.[2]

2. Further, the Commission approves NERC's revised definition of the term Remedial Action Scheme as set forth in the NERC Glossary of Terms Used in Reliability Standards (NERC Glossary), and modifications of specified Reliability Standards to incorporate the revised definition. Also, the Commission approves the associated implementation plans and assigned violation risk factors and violation severity levels for Reliability Standard EOP-011-1 and Reliability Standard PRC-010-1, as well as the retirement of certain currently-effective Reliability Standards.

I. Background

3. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight or by the Commission independently. In 2006, the Commission certified NERC as the ERO pursuant to FPA section 215.[3]

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

[3] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

4. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including initial versions of EOP-001, EOP-002, and EOP-003.[4] In addition, the Commission directed NERC to develop certain modifications to the EOP standards. In Order No. 693, the Commission also approved several Undervoltage Load Shedding (UVLS)-related Reliability Standards, including PRC-010-0, PRC-021-1 and PRC-022-1.[5] Further, the Commission directed NERC to modify Reliability Standard PRC-010-0 to develop an "integrated and coordinated" approach to all protection systems.[6] In Order No. 693, the Commission approved the NERC Glossary, including NERC's currently-effective Special Protection System and Remedial Action Scheme definitions.

II. NERC Petitions

5. NERC submitted three related petitions that we address together in this Final Rule.[7]

[4] Order No. 693, FERC Stats. and Regs. ¶ 31,242.

[5] *Id.* PP 1509, 1560, and 1565. The Commission neither approved nor rejected proposed Reliability Standard PRC-020-1, explaining that the standard only applied to Regional Reliability Organizations. *Id*. P 1555.

[6] *Id.* P 1509.

[7] Reliability Standards EOP-011-1 and PRC-010-1 are not attached to this Final Rule, nor are the additional Reliability Standards that NERC proposes to modify to incorporate the term Remedial Action Scheme. The Reliability Standards are available on the Commission's eLibrary document retrieval system in the identified dockets and on the NERC website, www.nerc.com.

A. NERC EOP Petition – Reliability Standard EOP-011-1 (Docket No. RM15-7-000)

6. On December 29, 2014, NERC filed a petition seeking Commission approval of Reliability Standard EOP-011-1, a revised definition of "Energy Emergency" and the associated violation risk factors and violation severity levels, effective date and implementation plan. NERC stated that the purpose of Reliability Standard EOP-011-1 is "to address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plans to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator area."[8] NERC explained that Reliability Standard EOP-011-1 consolidates the requirements of three existing standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 "into a single Reliability Standard that clarifies the critical requirements for Emergency Operations while ensuring strong communication and coordination across the functional entities."[9] NERC also asserted that Reliability Standard EOP-011-1 satisfies seven Commission directives set forth in Order No. 693.[10]

7. NERC noted that Reliability Standard EOP-011-1, Requirements R2 and R6 incorporate Attachment 1, which describes three Energy Emergency levels used by the

[8] NERC EOP Petition at 2.

[9] *Id*. at 3.

[10] *Id*. at 12-18.

reliability coordinator and the process for communicating the condition of a balancing authority experiencing an Energy Emergency.[11]

8. Reliability Standard EOP-011-1 includes six requirements, and is applicable to balancing authorities, reliability coordinators and transmission operators. Requirement R1 requires transmission operators to develop, maintain and implement reliability coordinator-reviewed operating plans to mitigate operating emergencies in its "transmission operating area."[12] Requirement R1 provides that, "as applicable," operating plans must: (1) describe the roles and responsibilities for activating the operating plan; and (2) include processes to prepare for and mitigate emergencies, such as Reliability Coordinator notification, transmission system reconfiguration, and redispatch of generation. NERC explained that Requirement R1 uses the phrase "as applicable" to provide "flexibility to account for regional differences and pre-existing methods for mitigating emergencies."[13] NERC added that an entity's decision to omit an element as not "applicable" must include an explanation in its plan. NERC further explained that the

[11] Attachment 1 describes three alert levels: Energy Emergency Alert Level 1 (all available generation resources in use, concern about sustaining required contingency reserves); Energy Emergency Alert Level 2 (load management procedures in effect, energy deficient balancing authority implements its emergency Operating Plan but maintains minimum contingency reserve requirements); and Energy Emergency Alert Level 3 (firm load interruption is imminent or in process, energy deficient balancing authority unable to maintain minimum contingency reserve requirements).

[12] Operating Plan is defined in the NERC Glossary as a "document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes…"

[13] NERC EOP Petition at 9.

requirement for transmission operators to maintain operating plans includes the expectation that the plans are current and up-to-date.[14]

9. Requirement R2 requires balancing authorities to develop, maintain and implement reliability coordinator-reviewed operating plans to mitigate capacity and energy emergencies in its "balancing authority area." Similar to the operating plans developed by transmission operators pursuant to the first requirement, the elements of the operating plans developed by balancing authorities allow for flexibility, provided an explanation is provided for omitted elements.[15]

10. Requirement R3 requires reliability coordinators to review the operating plans submitted by transmission operators and balancing authorities and is designed to ensure that there is appropriate coordination of reliability risks identified in the operating plans. In reviewing operating plans, reliability coordinators shall consider compatibility, coordination and inter-dependency with other entity operating plans and notify transmission providers and balancing authorities if revisions to their operating plans are necessary.[16]

11. Requirement R4 requires transmission operators and balancing authorities to resolve any issues identified by the reliability coordinator and resubmit their revised operating plans within a time period specified by the reliability coordinator. Requirement

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[14] *Id*. at 8-9.

[15] *Id*.

[16] *Id.* at 10-11.

R5 requires reliability coordinators to notify balancing authorities and transmission operators in its area, and neighboring reliability coordinators, within 30 minutes of receiving an emergency notification. Requirement R6 requires a reliability coordinator with a balancing authority experiencing a potential or actual Energy Emergency to declare an Energy Emergency alert in accordance with Attachment 1.

12. Proposed Reliability Standard EOP-011-1 also includes the following revised definition of Energy Emergency:

> Energy Emergency—A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.

NERC explained that the revised definition is intended to clarify that an Energy Emergency is not limited to a load-serving entity and, based on a review of the impact on the body of NERC Reliability Standards, "does not change the reliability intent of other requirements of Definitions."[17]

13. NERC proposed an effective date for Reliability Standard EOP-011-1 that is the first day of the first calendar quarter that is 12 months after the date of Commission approval, and a retirement date for currently-effective Reliability Standards EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 of midnight of the day immediately prior to the effective date of Reliability Standard EOP-011-1.

[17] *Id.* at 18.

B. NERC PRC Petition – Proposed Reliability Standard PRC-010-1 (Docket No. RM15-12-000)

14. On February 6, 2015, NERC filed a petition seeking approval of Reliability Standard PRC-010-1 (Undervoltage Load Shedding), a revised definition of Undervoltage Load Shedding Program (UVLS Program) for inclusion in the NERC Glossary, and the associated violation risk factors, violation severity levels, effective date and implementation plan. NERC also proposed the retirement of four PRC Reliability Standards.[18] NERC stated that the purpose of Reliability Standard PRC-010-1 is to "establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs" as directed by the Commission in Order No. 693.[19]

15. NERC explained that Reliability Standard PRC-010-1 is a single, comprehensive standard that addresses the same reliability principles outlined in the four currently-effective UVLS-related Reliability Standards.[20] Reliability Standard PRC-010-1 replaces the applicability to and involvement of "Regional Reliability Organization" in Reliability Standards PRC-020-1 and PRC-021-1 and improves upon and consolidates the four currently-effective UVLS-Related Standards into one comprehensive standard. NERC

[18] Reliability Standards PRC-010-0 (Assessment of the Design and Effectiveness of UVLS Program); PRC-020-1 (Under-Voltage Load Shedding Program Database); PRC-021-1 (Under-Voltage Load Shedding Program Data); and PRC-022-1 (Under-Voltage Load Shedding Program Performance).

[19] NERC PRC Petition at 14 (citing Order No. 693, FERC Stats & Regs ¶ 31,242 at P 1509).

[20] *Id.*

explained that Reliability Standard PRC-010-1 "reflects consideration of the 2003 Blackout Report recommendations,"[21] particularly, Recommendation 21 for NERC to "make more effective and wider use of system protection measures"[22] and Recommendation 21C for NERC to "determine the goals and principles needed to establish an integrated approach to relay protection for generators and transmission lines, as well as of UFLS and UVLS programs."[23]

16. Reliability Standard PRC-010-1 incorporates a new definition of UVLS Program, which reads:

> **Undervoltage Load Shedding Program (UVLS Program)**: An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.

NERC explained that "to ensure that the applicability of the proposed Reliability Standard covers undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System. By focusing on the enumerated risks, the definition is meant to exclude locally-

[21] *Id.* at 2 (citing the U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April, 2004 (2003 Blackout Report)).

[22] *Id.* at 4 (citing 2003 Blackout Report at 3, 158).

[23] *Id.* at 6.

applied relays that are not designed to mitigate wide-area voltage collapse."[24] NERC stated that the UVLS Program definition "clearly identifies and separates centrally controlled undervoltage-based load shedding, which is now addressed by the proposed definition of Remedial Action Scheme."[25]

17. Reliability Standard PRC-010-1 applies to planning coordinators and transmission planners because "either may be responsible for designing and coordinating the UVLS Program…[and] also applies to Distribution Providers and Transmission Owners responsible for the ownership, operation and control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator."[26] NERC explained that the planning coordinator or transmission planner that establishes a UVLS Program is responsible for identifying the UVLS equipment and the necessary distribution provider and transmission owner (referred to as "UVLS entities" in the Applicability section) that performs the required actions.

18. NERC stated that Reliability Standard PRC-010-1 "applies only after an entity has determined the need for a UVLS Program as a result of its own planning studies."[27] NERC explained that the eight requirements in Reliability Standard PRC-010-1 meet four primary objectives: (1) the Reliability Standard requires applicable entities to evaluate a

[24] *Id.* at 16.

[25] *Id.* at 15. NERC's petition for approval of the proposed definition of Remedial Action Scheme (Docket No. RM15-13-000) is discussed below.

[26] *Id.*

[27] *Id.* at 14.

UVLS Program's effectiveness prior to implementation, including coordination with other protection systems and generator voltage ride-through capabilities; (2) applicable entities must comply with UVLS program specifications and implementation schedule; (3) applicable entities must perform periodic assessment and performance analysis; and (4) applicable entities must maintain and share UVLS Program data.[28]

19. Requirement R1 requires each planning coordinator or transmission planner to evaluate the viability and effectiveness of its UVLS program before implementation to confirm its effectiveness in resolving the undervoltage conditions for which it was designed, and that it is integrated through coordination with generator ride-through capabilities and other protection and control systems. Also, the planning coordinator or transmission planner must provide the UVLS Program specifications and implementation schedule to the applicable UVLS entities. Requirement R2 requires UVLS entities to meet the UVLS Program's specifications and implementation schedule provided by the planning coordinator or transmission planner or address any necessary corrective actions in accordance with Requirement R5.

20. Requirement R3 requires each planning coordinator or transmission planner to perform periodic comprehensive assessments at least every 60 calendar months to ensure continued effectiveness of the UVLS program, including whether the program resolves identified undervoltage issues and that it is integrated and coordinated with generator

[28] *Id.* at 17.

voltage ride-through capabilities and other specified protection and control systems. Requirement R4 requires each planning coordinator or transmission planner to commence a timely assessment of a voltage excursion subject to the UVLS Program, within 12 calendar months of the event, to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event. Requirement R5 requires a corrective action plan for any program deficiencies identified during an assessment performed under either Requirement R3 or R4, and provide an implementation schedule to UVLS entities within three calendar months of its completion.

21. Pursuant to Requirement R6, a planning coordinator must update the data necessary to model its UVLS Program for use in event analyses and program assessments at least each calendar year. Requirement R7 requires each UVLS entity to provide data to its planning coordinator, according to the planning coordinator's format and schedule, to support maintenance of the UVLS Program database. Requirement R8 requires a planning coordinator to provide its UVLS Program database to other planning coordinators and transmission planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request.

22. NERC proposed an effective date for Reliability Standard PRC-010-1 and the definition of UVLS Program of the first day of the first calendar quarter that is 12 months after the date that the standard and definition are approved by the Commission. NERC proposed to retire PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1 at midnight of

the day immediately prior to the effective date of PRC-010-1.[29] Further, NERC explained that Reliability Standard PRC-010-1 addresses reliability obligations that are set forth in Requirements R2, R4 and R7 of currently-effective Reliability Standard EOP-003-2.[30] Since NERC has proposed to retire EOP-003-2 in the petition seeking approval of Reliability Standard EOP-011-1 (Docket No. RM15-7-00, discussed above), concurrent Commission action on the two petitions will prevent a possible reliability gap.

C. NERC RAS Petition – Revisions to the Definition of "Remedial Action Scheme" (Docket No. RM15-13-000)

23. On February 3, 2015, NERC filed a petition seeking approval of a revised definition of Remedial Action Scheme in the NERC Glossary, as well as modified Reliability Standards that incorporate the new Remedial Action Scheme definition and eliminate use of the term Special Protection System, and the associated implementation plan.[31] NERC stated that the defined terms Special Protection System and Remedial Action Scheme are currently used interchangeably throughout the NERC Regions and in various Reliability Standards. NERC explained that "[a]lthough these defined terms share a common definition in the NERC Glossary of Terms today, their use and

[29] *Id.* Ex. B (Implementation Plan).

[30] *Id.* at 23.

[31] NERC RAS Petition at 1-2. NERC requested approval of the following Reliability Standards to incorporate the proposed definition of Remedial Action Scheme and eliminate use of the term Special Protection System: EOP-004-3, PRC-005-3(ii), PRC-023-4, FAC-010-3, TPL-001-0.1(i), FAC-011-3, TPL-002-0(i)b, MOD-030-3, TPL-003-0(i)b, MOD-029-2a, PRC-015-1, TPL-004-0(i)a, PRC-004-WECC-2, PRC-016-1, PRC-001-1.1(i), PRC-005-2(ii), PRC-017-1. NERC did not propose any changes to the Violation Risk Factors or Violation Severity Levels for the modified standards.

application have been inconsistent as a result of a lack of granularity in the definition and varied regional uses of the terms. The proposed revisions add clarity and granularity that will allow for proper identification of Remedial Action Schemes and a more consistent application of related Reliability Standards."[32]

24. NERC explained that the revised Remedial Action Scheme definition consists of a "core" definition, including a list of objectives and a separate list of exclusions for certain schemes or systems not intended to be covered by the revised definition.[33] NERC stated that a broad definition is needed because of "all the possible scenarios an entity may develop" for its Remedial Action Scheme and a "very specific, narrow definition may unintentionally exclude schemes that should be covered."[34] Accordingly, NERC proposed the following revised "core" definition of Remedial Action Scheme:

> A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). (sic) RAS accomplish objectives such as:
> - Meet requirements identified in the NERC Reliability Standards;
> - Maintain Bulk Electric System (BES) stability;
> - Maintain acceptable BES voltages;
> - Maintain acceptable BES power flows;
> - Limit the impact of Cascading or extreme events.

[32] *Id.* at 4-5.

[33] *Id.* at 16. NERC noted that "for each exclusion, the scheme or system could still classify as a Remedial Action Scheme if employed in a broader scheme that meets the definition of Remedial Action Scheme."

[34] *Id.* at 17.

The definition then lists fourteen exclusions, describing specific schemes and systems that do not constitute a Remedial Action Scheme, because each is either a protection function, a control function, a combination of both, or used for system configuration.[35]

25. In the implementation plan, NERC proposed an effective date for the revised Reliability Standards and the revised definition of Remedial Action Scheme on the first day of the first calendar quarter that is 12 months after Commission approval. [36] NERC also proposed that, for entities with existing schemes that become newly classified as "Remedial Action Schemes" resulting from the application of the revised definition, the entities will have additional time of up to 24 months from the effective date to be fully compliant with all applicable Reliability Standards.[37] Further, NERC asked the Commission to take final action concurrently with the NERC petition on proposed Reliability Standard PRC-010-1 (Docket No. RM15-12-000) because "[t]he proposed definitions of UVLS Program and Remedial Action Scheme in each project have been coordinated to cover centrally controlled UVLS as a Remedial Action Scheme. Final action by the Commission is needed contemporaneously on both petitions to facilitate implementation and avoid a gap in coverage of centrally controlled UVLS."[38]

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[35] *Id.* at 18.

[36] NERC RAS Petition, Ex. C (Implementation Plan) at 4.

[37] *Id.*

[38] NERC RAS Petition at 3-4.

III. Notice of Proposed Rulemaking

26. On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve the Reliability Standards and NERC Glossary definitions set forth in NERC's three petitions pertaining to EOP-011-1, PRC-010-1 and a revised definition of Remedial Action Scheme as just, reasonable, not unduly discriminatory or preferential and in the public interest.[39] The Commission also proposed to approve the related violation risk factors, violation severity levels and implementation plans.

27. The Commission proposed to approve the retirement of Reliability Standards EOP-001-2.1b, EOP-002-3.1, EOP-003-2, PRC-010-0, PRC-020-1 and PRC-021-1. However, the Commission expressed concerns about whether it was appropriate to retire PRC-022-1 before a replacement Reliability Standard is approved and implemented to address the potential misoperation of UVLS equipment. Accordingly, the Commission proposed to deny NERC's request to retire Reliability Standard PRC-022-1 concurrent with the effective date of PRC-010-1.

28. In the NOPR, the Commission stated that Reliability Standards EOP-011-1 and PRC-010-1 provide greater clarity and that the consolidation of currently-effective EOP and PRC standards provides additional efficiencies for responsible entities. The Commission also agreed with NERC that the new definition of Remedial Action Scheme

[39] *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Notice of Proposed Rulemaking, 80 FR 36,293 (June 24, 2015), 151 FERC ¶ 61,230 (2015) (NOPR).

will improve reliability by eliminating ambiguity and encouraging the consistent identification of Remedial Action Schemes and a more consistent application of related Reliability Standards.

29. While the Commission proposed to approve Reliability Standard PRC-010-1, the Commission raised questions and sought clarification regarding an example of a "BES subsystem" that NERC provided in the "Guidelines for UVLS Program Definition." The Commission indicated that, depending on the response from NERC and others, a directive for further modification may be appropriate.[40]

30. In response to the NOPR, the Commission received comments from: NERC, Edison Electric Institute (EEI), Peak Reliability, Transmission Access Policy Study Group (TAPS), International Transmission Company (ITC), Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E/KU) and Idaho Power Company (Idaho Power).

IV. Discussion

31. Pursuant to FPA section 215(d)(2), we approve Reliability Standards EOP-011-1 and PRC-010-1, the revised definition of Remedial Action Scheme and NERC Glossary definitions, and associated violation risk factors and violation severity levels and implementation plans as just, reasonable, not unduly discriminatory or preferential and in the public interest. The Commission believes that the modified Reliability Standards provide greater clarity, and the consolidated EOP and PRC standards will provide

[40] NOPR, 151 FERC ¶ 61,230 at P 27.

additional efficiencies for responsible entities. We also determine that Reliability Standard EOP-011-1 adequately addresses seven Order No. 693 directives, and that Reliability Standard PRC-010-1 establishes an integrated and coordinated approach to the design, evaluation and reliable operation of UVLS Programs, and therefore satisfies the Commission directive issued in Order No. 693.[41] Further, we approve the retirement of certain Reliability Standards as identified by NERC.[42]

32. We discuss below the following issues raised in the NOPR and comments: (1) the deregistration of load-serving entities and Reliability Standard EOP-011-1; (2) the scheduling and scope of reliability coordinator reviews of Operating Plans under Reliability Standard EOP-011-1; (3) the retirement of Reliability Standard PRC-022-1; (4) the term "BES subsystem" and related diagram in NERC's PRC Petition; and (5) other issues raised by commenters.

A. Reliability Standard EOP-011-1

1. The Deregistration of Load-Serving Entities

NOPR

33. In the NOPR, while proposing to approve Reliability Standard EOP-011-1 and a new Energy Emergency definition, the Commission stated that the removal of load-

[41] Order No. 693, FERC Stats & Regs. ¶ 31,242 at P 1509.

[42] As noted above, the Commission in Order No. 693 did not approve or remand proposed Reliability Standard PRC-020-1 but, rather, took no action on the Reliability Standard pending the receipt of additional information. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1555. Our approval of NERC's request renders PRC-020-1 "retired," i.e., withdrawn, and no longer pending before the Commission.

serving entities from the Reliability Standard raises questions about who would perform the roles traditionally performed by load-serving entities.[43] The NOPR explained that the Commission's decision concerning NERC's compliance filing in Docket No. RR15-4-000 related to NERC's Risk-Based Registration initiative would guide the Commission's action on this question in this proceeding.

Comments

34. NERC, EEI, TAPS, ITC and Idaho Power support the Commission's proposed approval of Reliability Standard EOP-011-1. Further, NERC, EEI and TAPS state that excluding load-serving entities from the Reliability Standard will not create a reliability gap. NERC states that currently-effective Reliability Standard EOP-002-3.1 Requirement R9 is the only requirement in the three Reliability Standards being replaced by Reliability Standard EOP-011-1 that applies to load-serving entities. NERC explains that the North American Energy Standards Board (NAESB) has modified the process for E-tag specifications, removing the load-serving entities' role in making changes to the priority of transmission service requests. Therefore, the "Standard Drafting Team did not incorporate Requirement R9 into Reliability Standard EOP-011-1, because Requirement R9 has become obsolete due to technological changes."[44]

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[43] NOPR, 151 FERC ¶ 61,230 at P 24, n.36. Currently effective EOP-002-3.1 applies, *inter alia*, to load-serving entities. Reliability Standard EOP-011-1 replaces EOP-002-3.1, and applies to balancing authorities, reliability coordinators and transmission operators, but not load-serving entities.

[44] NERC Comments at 4.

35. Additionally, NERC explains that, due to the Real-time nature of energy emergencies, balancing authorities and distribution providers will handle responsibilities related to Reliability Standard EOP-002-3.1 that have been performed by load-serving entities. Referring to the Mapping Document and Application Guidelines for Reliability Standard EOP-011-1, NERC states that "LSEs have no Real-time reliability functionality with respect to EEAs [Energy Emergency Alerts]."[45]

36. TAPS and EEI agree with NERC's analysis of the roles and responsibilities of load-serving entities and that excluding them will not create any reliability gaps. TAPS states that "there is no reliability benefit to retaining EOP-002-3.1's Requirement R9, and thus no reliability risk from eliminating the LSE obligation to comply with it."[46] EEI asserts that "NERC is correct that 'tasks currently assigned to the LSE function under NERC Reliability Standards would continue to be performed by other functions subject to currently applicable LSE Reliability Standard Requirements or by market participants (including LSEs) pursuant to existing tariffs, market rules, market protocols and other market agreements.'"[47] Regarding Operating Plans that transmission operators and balancing authorities are to develop under Reliability Standard EOP-011-1 Requirements R1 and R2, EEI states that "it is clear that the responsible entities required to perform the activities attributed to the LSE function necessary to aid in arresting an Energy

[45] *Id.* at 5-6.

[46] TAPS Comments at 4.

[47] EEI Comments at 5-6, quoting NERC's compliance filing in RR15-4-000 at 1.

Emergency must be identified to ensure necessary mitigation can be accomplished in order to ensure reliable operation of the BES."[48]

37. LG&E/KU seeks clarification on two questions pertaining to the exclusion of load-serving entities from Reliability Standard EOP-011-1 "to ensure that even if NERC's EOP proposal is accepted, [balancing authorities] will have a meaningful way of addressing any operational gaps with Energy Emergencies and LSEs."[49] First, LG&E/KU seeks clarification that an Energy Emergency can be isolated to a load-serving entity's inability to meet its own load obligations, as indicated in NERC's revised definition of Energy Emergency. Second, LG&E/KU seeks clarification that Operating Plans developed by balancing authorities may describe the role for load-serving entities in responding to an Energy Emergency, and may include such Operating Plans in applicable tariffs.

Commission Determination

38. Consistent with our determination in the "risk-based registration" proceeding, we find that the elimination of load-serving entities from Reliability Standard EOP-011-1 will not prevent the Reliability Standard from achieving its stated purposes or otherwise create reliability gaps.[50] We find that Reliability Standard EOP-011-1 enhances

[48] *Id.* at 6.

[49] LG&E/KU Comments at 2.

[50] *See North American Electric Reliability Corp.*, 153 FERC ¶ 61,024, at P 20 (2015) (RBR Compliance Order) (approving the proposed elimination of the load-serving entity function).

reliability by requiring that actions necessary to mitigate capacity and energy emergencies are focused in single operating plans, and ensures communication and coordination among relevant entities during emergency operations. We are persuaded by NERC's explanation that excluding load-serving entities will not adversely impact reliability due to technological changes concerning NAESB tagging specifications, and that load-serving entities "have no Real-time reliability functionality with respect to EEAs [Energy Emergency Alerts]."[51] Further, as both NERC and EEI have stated, "tasks currently assigned to the LSE function under NERC Reliability Standards would continue to be performed by other functions subject to currently applicable LSE Reliability Standard Requirements or by market participants (including LSEs) pursuant to tariffs, market rules, market protocols and other market agreements." [52]

39. We disagree with LG&E/KU's suggestion that the reference to load-serving entities in NERC's revised definition of Energy Emergency indicates the possibility of an "operational gap." NERC revises the definition of "Energy Emergency," approved in this Final Rule, as "[a] condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations."[53] Based on a plain reading of this definition, we agree with LG&E/KU that a load-serving entity's inability to meet its own load obligations could result in an Energy

[51] NERC Comments at 5, quoting the EOP-011-1 Mapping Document and Application Guidelines.

[52] EEI Comments at 5-6.

[53] NERC EOP Petition, Ex. B (Implementation Plan) at 1.

Emergency. Moreover, consistent with our findings in the RBR Compliance Order, we agree with LG&E/KU that operating plans developed by balancing authorities – including operating plans contained in applicable tariffs - may describe the role for load-serving entities in responding to an Energy Emergency.[54] EEI's observation regarding Reliability Standard EOP-011-1 Requirements R1 and R2 for transmission operators and balancing authorities to develop Operating Plans to mitigate Energy Emergencies reinforces this determination: "[a]lthough these requirements do not specifically identify the 'who' or 'what' actions to be taken, it is clear that the responsible entities required to perform the activities attributed to the LSE function necessary to aid in arresting an energy emergency must be identified to ensure necessary mitigation can be accomplished in order to ensure reliable operation of the BES."[55] Accordingly, we conclude that elimination of the load-serving entity function from Reliability Standard EOP-011-1 does not result in an operational gap and, rather, provides a reasonable means of addressing Energy Emergencies.

2. The Scheduling and Scope of Reliability Coordinator Reviews of Operating Plans

40. Reliability Standard EOP-011-1, Requirement R3 obligates a reliability coordinator to review the Operating Plan(s) to mitigate operating emergencies submitted by a transmission operator or a balancing authority. Pursuant to Requirement R3.1, a

[54] RBR Compliance Order, 153 FERC ¶ 61,024 at 21.

[55] EEI Comments at 6.

reliability coordinator must, within 30 days of receipt, (i) review each Operating Plan for compatibility and inter-dependency with other transmission operator or balancing authority Operating Plans, (ii) review each Operating Plan for coordination to avoid risk to "Wide Area" reliability, and (iii) notify each transmission operator and balancing authority of the results of the review.

Comments

41. Peak Reliability asserts that the "inflexible" 30 day period for reliability coordinator reviews of operating plans in Reliability Standard EOP-011-1 Requirement R3.1 is not reasonable. According to Peak Reliability, because transmission operators have an "open ended" opportunity to submit operating plans under the provision, reliability coordinators cannot schedule in advance the needed resources to perform a proper review in the 30-day window. Peak Reliability notes that, in its experience, many entities update their plans at the end of the year, creating a large spike in review work at that time. Peak Reliability, therefore, recommends revising Requirement R3.1 to include language requiring "a mutually agreed predetermined schedule" to ensure that the reliability coordinator can efficiently allocate its resources and provide a thorough review of submitted operating plans.[56]

42. Peak Reliability also seeks clarification regarding the scope of reliability coordinator review of operating plans, and whether a reliability coordinator must review

[56] Peak Reliability Comments at 6-7.

each required element of an operating plan specified in Requirement R2 for "compatibility and interdependency" with other balancing authority and transmission operator operating plans, or "evaluate these elements on a higher level."[57] Peak Reliability asserts that the "appropriate level of review" by reliability coordinators is "for coordination to avoid risk to Wide Area reliability." Based on this assertion, Peak Reliability recommends that Reliability Standard EOP-011-1 require balancing authorities and transmission operators to identify and coordinate possible operating plan discrepancies before submission for reliability coordinator review, as currently required under Reliability Standard EOP-001-2.1b Requirement R6.[58]

Commission Determination

43. We are not persuaded by Peak Reliability's comments that the 30 day review period in Requirement R3.1 is unduly onerous. No reliability coordinator other than Peak Reliability expressed concern about the 30 day review period for operating plans in Requirement R3.1. NERC explains that transmission operators and balancing authorities must update their operating plans on an "ongoing and as-needed basis."[59] The need for registered entities to update operating plans to address evolving bulk electric system conditions should prevent reliability coordinators from being overwhelmed or unduly burdened by operating plan submissions. However, if Peak Reliability experiences an

[57] *Id.* at 7.

[58] *Id.* at 7-8.

[59] *See* NERC EOP Petition at 9.

"end of the year spike in workload,"[60] as a reliability coordinator, Peak Reliability can adjust its resource allocation to accommodate such known "spikes" in activity. Accordingly, we conclude the 30 day review period in Requirement R3.1 is reasonable and reject Peak Reliability's recommendation for language requiring a "mutually agreed predetermined schedule."

44. Additionally, we believe that Peak Reliability's concern regarding the extent of reliability coordinator Operating Plan review for "compatibility and interdependency" under Reliability Standard EOP-011-1 Requirement 3.1.1 is misplaced. Based on the record before us, particularly the Standard Drafting Team's decision to require reliability coordinators to review rather than approve operating plans, and the ongoing nature of emergency planning, we conclude that Requirement R3.1.1 contemplates high level assessments focused on the coordination of operating plans between and among transmission operators and balancing authorities.[61] Moreover, while Peak Reliability may request that NERC (e.g., through a standard authorization request or "SAR") include a provision in EOP-011-1 to require coordination among transmission operators and balancing authorities prior to submitting an operating plan for reliability coordinator review, we are not persuaded to direct NERC to develop such a provision.

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[60] *See* Peak Reliability Comments at 5-6.

[61] *See* NERC EOP Petition, Exhibit G (Summary of Development History and Complete Record of Development) at 1166 (the Standard Drafting Team indicates that the provision is intended to require the reliability coordinator review of deficiencies, inconsistencies or conflicts between operating plans that would cause further system degradation during emergency conditions).

B. Reliability Standard PRC-010-1

1. Retirement of Reliability Standard PRC-022-1

NOPR

45. In the NOPR, while proposing to approve Reliability Standard PRC-010-1 and the retirement of PRC-010-0, PRC-020-1 and PRC-021-1, the Commission was not persuaded that Reliability Standard PRC-010-1, Requirement R4 is an adequate replacement for currently-effective PRC-022-1, which contains requirements specifically addressing misoperations. Rather, the Commission proposed that Reliability Standard PRC-022-1 would remain in effect until an acceptable replacement Reliability Standard is in place to address the potential misoperation of UVLS equipment.

Comments

46. NERC states that, on June 9, 2015, it filed proposed Reliability Standards PRC-010-2 and PRC-004-5 as part of its UVLS Phase II Petition (Project 2008-02.2), which includes requirements and applicability criteria related to UVLS misoperations.[62] NERC explains that its filing requests that the Commission approve Reliability Standards PRC-004-5 and PRC-010-2 concurrently with the Commission's action on Reliability Standard PRC-010-1 "to ensure an integrated and coordinated approach to UVLS Programs and fill the gap in Reliability Standard coverage that might be perceived through retirement of

[62] Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards PRC-004-5 and PRC-010-2, (Docket No. RD15-5-000).

PRC-022-1."[63] EEI agrees, stating that NERC's filing of proposed Reliability Standards PRC-004-5 and PRC-010-2 address the Commission's concerns expressed in the NOPR.[64]

Commission Determination

47. We agree with NERC and EEI that the Delegated Letter Order approval of Reliability Standards PRC-004-5 and PRC-010-2 in Docket No. RD15-5-000 concurrent with this Final Rule precludes the need to retain currently-effective Reliability Standard PRC-022-1.[65] Accordingly, we find that Reliability Standard PRC-022-1 can be retired without creating a gap in coverage with regard to UVLS protective relay misoperations and equipment performance evaluations.

2. The Term "BES Subsystem" and Related Diagram

NOPR

48. In the NOPR, the Commission sought clarification of the meaning of NERC's use of the term "BES subsystem" in a diagram illustrating a UVLS system that would not be included in the definition of UVLS Program if the consequences of the contingency do not impact the bulk electric system, and whether it would be considered a Remedial Action Scheme.[66]

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[63] NERC Comments at 8.

[64] EEI Comments at 7.

[65] *See* Delegated Letter Order issued November 19, 2915.

[66] *See* NOPR, 151 FERC ¶ 61,230 at P 27 (including diagram).

Comments

49. NERC comments that the term "BES subsystem" and accompanying diagram are "intended to demonstrate that whether PRC-010-1 applies to a UVLS system depends on whether the UVLS system is used to mitigate undervoltage conditions impacting areas of the BES, leading to voltage instability, voltage collapse or Cascading."[67] NERC also states that "the term 'BES subsystem' is a shorthand reference to an area of the BES that a Registered Entity is responsible for, consistent with its obligations under mandatory Reliability Standards. This reference does not revise the Commission-approved definition of 'Bulk Electric System' or create a new term."[68]

50. NERC explains that the diagram "is not intended to necessarily illustrate a centrally controlled UVLS (considered a [Remedial Action Scheme]), but to illustrate how Registered Entities should evaluate whether the term UVLS Program and proposed Reliability Standard PRC-010-1 applies to a UVLS system."[69] NERC points out that, if a UVLS system in the "BES subsystem" is used to mitigate undervoltage conditions impacting the BES (leading to voltage instability, voltage collapse, or Cascading), the system would fall under the new definition of UVLS Program (or RAS if centrally controlled) and thus in the scope of Reliability Standard PRC-010-1.[70]

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[67] NERC Comments at 6-7.

[68] *Id.* at 7.

[69] *Id.*

[70] *Id.*

51. EEI states that the example of "BES subsystem" in the "Guidelines for UVLS Program Definition" does not represent a centrally controlled UVLS and therefore would not be considered a Remedial Action Scheme. EEI explains that the term UVLS Program "is for a scheme that consists of distributed relays and controls, not for a scheme that is centrally controlled. The key point is that for a UVLS system to fall under the definition of Undervoltage Load Shedding Program, it must be used to protect the BES against voltage instability, voltage collapse, or Cascading."[71] EEI also notes that the term "BES subsystem" is not intended to be a new NERC term, but rather "was used in the example to illustrate a possible localized undervoltage contingency on a very small portion of the BES but not a contingency that impacts a larger area of the BES that could result in voltage instability, voltage collapse, or Cascading."[72]

Commission Determination

52. Based on the explanations provided above, we determine that a directive for further modification of the example of "BES subsystem" and related diagram in NERC's "Guidelines for UVLS Program Definition" to ensure consistency with the Commission-approved definition of "bulk electric system" proposed in the NOPR is not necessary. Rather, we are persuaded that EEI's concern with the diagram is addressed by NERC's explanation that, depending on the role of a particular UVLS system, the diagram could

[71] EEI Comments at 8.

[72] *Id.*

illustrate an example of a UVLS Program or a centrally-controlled Remedial Action Scheme.[73]

C. Other Issues Raised By Commenters

1. Reliability Standard PRC-010-1 – Applicability

53. Peak Reliability asserts that Reliability Standard PRC-010-1 "does not adequately address the operation of UVLS Programs, as it does not apply to the NERC functional entities that operate the Bulk Electric System," particularly, reliability coordinators, transmission operators, and balancing authorities.[74] Peak Reliability contends that UVLS Programs should be included in operational planning and real-time assessments, and that all entities responsible for operating the bulk electric system must be given access to UVLS Program databases.[75] Further, Peak Reliability requests that the Commission direct NERC to explain why Reliability Standard PRC-010-1 and Reliability Standard IRO-009-1 apply to different functional entities (since the purpose of both is to prevent instability, uncontrolled separation or cascading outages), and recommends that the treatment of UVLS in operations planning and real-time assessments be addressed.[76]

54. We are not persuaded by Peak Reliability's assertion that Reliability Standard PRC-010-1 should apply to reliability coordinators, transmission operators, and balancing authorities. Rather, as NERC explains "[t]he applicability includes both the Planning

[73] *Id.*

[74] Peak Reliability Comments at 9.

[75] *Id.* at 9-10.

[76] *Id.* at 11-12.

Coordinator and Transmission Planner because either may be responsible for designing and coordinating the UVLS Program. Reliability Standard PRC-010-1 also applies to Distribution Providers and Transmission Owners responsible for the ownership, operation and control of UVLS equipment as required by the UVLS Program established by the Transmission Planner and Planning Coordinator."[77] As NERC's rationale above indicates, the applicability section of the Reliability Standard identities the functional entities responsible for the design, operation and control of UVLS Programs and related equipment.

55. While Peak Reliability seeks to expand applicability to functional entities so that UVLS Program databases would be shared with reliability coordinators, transmission operators, and balancing authorities, we believe that this need to expand applicability is unfounded. Reliability Standard PRC-010-1, Requirement R8, provides that other functional entities with a reliability need can request UVLS data, and that such requests must be answered in 30 days.

56. Nor are we persuaded by Peak Reliability's argument that UVLS programs should be considered in operations planning and real-time operations. We understand that Peak Reliability refers to the consideration of UVLS programs in the derivation of Interconnection Reliability Operating Limits (IROLs) for Category B contingencies as defined in the currently-effective transmission planning standard TPL-002-0b (commonly

[77] NERC EOP Petition at 15, and id. Ex. D (Order No. 672 Criteria) at 2-3.

known as N-1 contingencies under normal system operation).[78] With this understanding, we disagree with Peak Reliability on the relevance of using UVLS in the derivation of IROLs for N-1 contingencies. The 2003 Canada-United States Blackout Report stated that "[s]afety nets should not be relied upon to establish transfer limits."[79] This statement is consistent with the performance criteria established in TPL-002-0b and TPL-001-4, which generally prohibit the loss of non-consequential load for certain N-1 contingencies.[80] We conclude that UVLS programs under PRC-010-1 are examples of such "safety nets" and should not be tools used by bulk electric system operators to calculate operating limits for N-1 contingencies. Likewise, with this understanding, there is no imperative to make PRC-010-1 applicable to reliability coordinators, transmission operators, and balancing authorities.

57. Peak Reliability comments that Reliability Standard PRC-010-1 "creates some confusion of the applicability of UVLS Programs due to the similarities, and apparent overlap, in the definitions of UVLS Programs and IROLs."[81] We disagree. Peak Reliability's comparison of UVLS Programs with establishing and operating within IROLs is misplaced because UVLS Programs and IROLs represent separate and distinct

[78] The Commission-approved Version 4 standard, TPL-001-4, will replace TPL-002-0b on January 1, 2016. *See Transmission Planning Reliability Standards*, Order No. 786, 145 FERC ¶ 61,051 (2013).

[79] 2003 Blackout Report at 109**.**

[80] *See* TPL-002-0b, Table 1, footnote b and TPL-001-4, Table 1, Footnote 12.

[81] Peak Reliability Comments at 11.

approaches to system security. UVLS Programs act as safety nets for contingencies more severe than N-1 contingencies, such as the simultaneous loss of two single circuits or a double-circuit line which are both Category C contingencies permitting loss of non-consequential firm load.[82] In contrast, the NERC Glossary defines IROLs as "[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System." This corresponds with the TPL-004-1 provisions requiring that the system must remain stable when experiencing an N-1 contingency (such as Category B or P1 contingencies).[83] In sum, we disagree with Peak Reliability's premise regarding similarities, and overlaps, in the definition of UVLS programs and IROLs.

2. Reliability Standard PRC-010-1 –Appropriate Level of Detail in UVLS Program Assessment

58. Reliability Standard PRC-010-1, Requirements R3, R4, and R5 obligate planning coordinators and transmission planners to perform an assessment of their UVLS program in various circumstances. Idaho Power contends that Reliability Standard PRC-010-1, Requirements R3, R4, and R5, do not "specifically state what must be included in the

[82] The TPL Standards require that the system remain stable and that cascading and uncontrolled islanding shall not occur for any Category B or C contingency (i.e., currently-effective TPL Standards, N-1 and N-2 contingencies) or for any Category P1 through P7 contingency (i.e., TPL-001-4, N-1 and N-2 contingencies.) *See* Table 1 of any of the TPL Standards.

[83] *See* TPL Standards, Table 1.

assessment, as was included in PRC-022-1 R1.1-4" and, therefore, do not sufficiently explain what applicable entities must include in UVLS Program assessments.[84]

59. We disagree with Idaho Power. Reliability Standard PRC-022-1 requires applicable entities to "analyze and document all UVLS operations and misoperations," and specifically mentions set points and tripping times and a summary of the findings. In contrast, Reliability Standard PRC-010-1 Requirement R3, requires planning coordinators and transmission planners to perform comprehensive assessments of their UVLS Programs at least once every 5 years. Each assessment "shall include, but is not limited to, studies and analyses that evaluate whether … the UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed [and] the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems." Requirement R4 requires applicable entities to assess whether UVLS programs resolve undervoltage issues associated with voltage excursions triggering UVLS programs. Pursuant to Requirement R5, planning coordinators and transmission planners must develop a corrective action plan to address UVLS program deficiencies identified during assessments performed under Requirements R3 and R4. We conclude that the comprehensive nature of the assessments required under Reliability Standard PRC-010-1 is sufficient, and precludes the need to include the specific items listed in PRC-022-1, Requirement R1.

[84] Idaho Power Comments at 2.

3. Definition of Special Protection System

60. ITC supports the approval of the revised definition of Remedial Action Scheme. ITC points out that NERC proposes to move to a single definition, Remedial Action Scheme, to eliminate the use of two terms, i.e., Special Protection System.[85] Thus, ITC requests that the Commission direct NERC to remove the definition of Special Protection System from the NERC Glossary to eliminate any potential for confusion.

61. We deny ITC's request that the Commission direct NERC to remove the definition of "Special Protection System" from the NERC Glossary. In its RAS Petition, NERC states that it "will continue to modify the NERC Reliability Standards until all of them reference only the defined term Remedial Action Scheme. At that time, the definition of Special Protection System will be retired."[86] We are satisfied with NERC's approach of retiring the term "Special Protection System" once the Reliability Standards are fully updated to reference the revised definition of Remedial Action Scheme.

V. Information Collection Statement

62. The collection of information contained in this Final Rule is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[87] OMB's regulations require approval of

[85] ITC Comment at 3.

[86] NERC RAS Petition at 5.

[87] 44 U.S.C. 3507(d).

certain informational collection requirements imposed by agency rules.[88] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

63. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the PRA. The NOPR solicited comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimate, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. No comments were received.

A. Proposed Reliability Standard EOP-011-1

64. Public Reporting Burden: As of March 2015, there are 105 balancing authorities, 11 reliability coordinators and 329 transmission operators registered with NERC. These registered entities will have to comply with 6-8 new requirements in the new proposed Reliability Standard EOP-011-1. As proposed, each registered balancing authority will have to comply with Requirements R2, R4, and, under certain circumstances, R5. Each reliability coordinator will have to comply with Requirements R1 and its subparts, R2

[88] 5 C.F.R. 1320.11.

and its subparts, R3 and its subparts, R5 and R6. Each transmission operator will have to comply with Requirements R1 and its subparts and R4.

65. Reliability Standard EOP-011-1 replaces a combined total of 40 requirements or subparts that are found in Reliability Standards EOP-001-2.1b, EOP-003.1 and EOP-003-2. These three Reliability Standards are to be retired, concurrent with the effective date of Reliability Standard EOP-011-1. Accordingly, the requirements in Reliability Standard EOP-011-1 do not create any new burdens for applicable balancing authorities or transmission operators because the requirements in Reliability Standard EOP-011-1 are already burdens or tasks imposed on this set of registered entities by Reliability Standards EOP-001-2.1b, EOP-003.1 and EOP-003-2 under FERC-725A (1902-0244).

66. Reliability Standard EOP-011-1 requires reliability coordinators to perform the additional tasks of reviewing, correcting, and coordinating their balancing authorities' and transmission operators' operating procedures for emergency conditions. The Commission estimates that this will add approximately 1,500 man-hours per year for each reliability coordinator as described in detail in the following table:

RM15-7-000 (Mandatory Reliability Standards: Reliability Standard EOP-011-1)						
	Number of Applicable Registered Entities (1)	***Annual Number of Responses per Respondent (2)***	***Total Number of Responses (1)*(2)=(3)***	***Average Burden (Hours) & Cost Per Response (4)***	***Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)***	***Cost per Respondent ($) (5)÷(1)***
RC tasks necessary for EOP-011-1 compliance	11	1	21	1,500 $92,387[89]	16,500 $1,016,257	$92,387

B. Proposed Reliability Standard PRC-010-1

Public Reporting Burden: As of April 2015, there are 467 registered distribution providers and 50 transmission providers that are not overlapping in their registration with the distribution provider registration. We estimate that five percent of all distribution providers (23) and transmission providers (3) have under voltage load shedding programs that fall under the Reliability Standard. The Reliability Standard is applicable to planning coordinators and transmission planners, distribution providers, and transmission owners. However, only distribution providers and transmission owners would be responsible for the incremental compliance burden under Reliability Standard PRC-010-1, Requirement R2, as described in detail in the following table:

[89] The 1,500 hour figure is broken into 1300 hours at the engineer wage rate and 200 hours at the clerk wage rate. These estimates assume that the engineer's wage rate will be $66.35 and the clerk's wage rate will be $30.66. These figures are taken from the Bureau of Labor Statistics at http://www.bls.gov/oes/current/naics2_22.htm; Occupation Code: 17-2071 (engineer) and 43-4071 (clerk).

RM15-12-000 (Mandatory Reliability Standards: Reliability Standard PRC-010-1)[90]						
	Number of Applicable Registered Entities (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden (Hours) & Cost Per Response (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
DP – Requirement 2	23	1	23	36[91] $1,960.32	828 $45,087.36	$1,960
TP - Requirement 2	3	1	3	36[92] $1,960.32	108 $5,880.96	$1,960
DP - R2 Data Retention	23	1	23	12 $367.92[93]	276 $8,462.16	$368
TP – R2 Data Retention	3	1	3	12 $367.92	36 $1,103.76	$368
TOTAL					$60,534.24	

C. Remedial Action Scheme Revisions

67. Public Reporting Burden: The Commission approved the definition of Special Protection System (Remedial Action Scheme) in Order No. 693. We approve a revision to the previously approved definition. The revisions to the Remedial Action Scheme definition and related Reliability Standards are not expected to result in changes to the scope of systems covered by the Reliability Standards and other Reliability Standards that

[90] DP = distribution provider and TP = transmission provider.

[91] The 36 hour figure is broken into 24 hours at the engineer wage rate and 12 hours at the clerk wage rate. These estimates assume that the engineer's wage rate will be $66.35 and the clerk's wage rate will be $30.66. These figures are taken from the Bureau of Labor Statistics at http://www.bls.gov/oes/current/naics2_22.htm; Occupation Code: 17-2071 (engineer) and 43-4071 (clerk).

[92] *Id.*

[93] Clerk's wage rate is used for managing data retention.

include the term Remedial Action Scheme. Therefore, the Commission does not expect the revisions to affect applicable entities' current reporting burden.

FERC-725G4, Mandatory Reliability Standards: Reliability Standard PRC-010-1 (Undervoltage Load Shedding).

FERC-725S, Mandatory Reliability Standards: Reliability Standard EOP-011-1 (Emergency Operations).

Action: Proposed Collection of Information.

OMB Control No: OMB Control No. 1902-0270 (FERC-725S); OMB Control No. 1902-XXXX (FERC-725G4).

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: One time and on-going.

Necessity of the Information: The revision to NERC's definition of the term bulk electric system implements the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the Reliability Standards consolidate, streamline and clarify the existing requirements of certain currently-effective Emergency Preparedness and Operations and Protection and Control Reliability Standards.

68. Internal review: The Commission has reviewed the requirements pertaining to Reliability Standards PRC-010-1 and EOP-011-1 and made a determination that the requirements of these Reliability Standards are necessary to implement section 215 of the FPA. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The

Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

69. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

70. Comments concerning the information collections in this Final Rule and the associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference the docket number of this Final Rule (Docket Nos. RM15-13-000, RM15-12-000, and RM15-7-000) in your submission.

VI. Regulatory Flexibility Act Certification

71. The Regulatory Flexibility Act of 1980 (RFA)[94] generally requires a description and analysis of Proposed Rules that will have significant economic impact on a substantial number of small entities.

72. Reliability Standard EOP-011-1 is expected to impose an additional burden on 11 entities (reliability coordinators). The remaining 434 entities (balancing authorities

[94] 5 U.S.C. 601-12.

and transmission operators and a combination thereof) will maintain the existing levels of burden. Comparison of the applicable entities with FERC's small business data indicates that approximately 7 of the 11 entities are small entities, or 63.63 percent of the respondents affected by this Reliability Standard.[95]

73. On average, each small entity affected may have a one-time cost of $92,387 representing a one-time review of the program for each entity, consisting of 1,500 man-hours at $66.35/hour (for engineer wages) and $30.66/hour (for record clerks), as explained above in the information collection statement.

74. Reliability Standard PRC-010-1 is expected to impose an additional burden on 26 entities (distribution providers and transmission providers or a combination thereof). Comparison of the applicable entities with FERC's small business data indicates that approximately 8 of the 26 entities are small entities, or 30.77 percent of the respondents affected by this Reliability Standard.

75. On average, each small entity affected may have a cost of $1,960, representing a one-time review of the program for each entity, consisting of 36 man-hours at $66.35/hour (for engineer wages) and $30.66/hour (for record clerks), as explained above in the information collection statement. Regarding the revisions to the Remedial Action

[95] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 500 employee threshold for each affected entity. Each entity is classified as Electric Bulk Power Transmission and Control (NAICS code 221121).

Scheme definition and the related Reliability Standards including the revised definition, as discussed above, the Commission estimates that proposals will have no cost impact on applicable entities, including any small entities.

76. The Commission estimates that Reliability Standards EOP-011-1 and PRC-010-1 in this Final Rule impose an additional burden on a total of 37 entities. FERC's small business data indicates that 15 of the 37 respondents are small entities, or 40.54 percent of the respondents affected by these proposed Reliability Standards. On average, each small entity affected may have a cost of $92,387 and $1,960 (EOP-011-1 and PRC-010-1 respectively), representing a one-time review of the program for each entity. We do not consider these costs to be a significant economic impact on small entities. Accordingly, the Commission certifies that Reliability Standards EOP-011-1 and PRC-010-1 will not have a significant economic impact on a substantial number of small entities.

VII. Environmental Analysis

77. 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.[96] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being

[96] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

amended.[97] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VIII. Document Availability

78. 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.

79. 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.

80. 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.

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[97] 18 C.F.R. 380.4(a)(2)(ii).

IX. Effective Date and Congressional Notification

81. This Final Rule is effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.[98] The Commission will submit the final rule to both houses of Congress and to the General Accountability Office.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[98] *See* 5 U.S.C. 804(2).

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153 FERC ¶ 61,220

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM15-2-000; Order No. 819]

Third-Party Provision of Primary Frequency Response Service

(Issued November 20, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is revising its regulations to foster competition in the sale of primary frequency response service. Specifically, the Commission amends its regulations governing market-based rates for public utilities pursuant to the Federal Power Act (FPA) to permit the sale of primary frequency response service at market-based rates by sellers with market-based rate authority for sales of energy and capacity.

EFFECTIVE DATE: This Final Rule will become effective **[Insert date 90 days after publication in the FEDERAL REGISTER]**.

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SUPPLEMENTARY INFORMATION:

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153 FERC ¶ 61,220
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Third-Party Provision of Primary Frequency Response Service — Docket No. RM15-2-000

ORDER NO. 819

FINAL RULE

(Issued November 20, 2015)

1. The Federal Energy Regulatory Commission (Commission) is revising its regulations to foster competition in the sale of primary frequency response service.[1] Specifically, the Commission amends its regulations to revise Subpart H to Part 35 of Title 18 of the Code of Federal Regulations governing market-based rates for public utilities pursuant to sections 205 and 206 of the Federal Power Act (FPA)[2] to permit the sale of primary frequency response service at market-based rates by sellers with market-based rate authority for sales of energy and capacity.

[1] As described in more detail below, this Final Rule defines primary frequency response service as a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over.

[2] 16 U.S.C. 824d, 824e (2012).

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2. This proceeding derives from Order No. 784,[3] in which the Commission revised Part 35 of its regulations to reflect reforms to its *Avista* policy[4] governing the sale of certain ancillary services at market-based rates to public utility transmission providers. Specifically, Order No. 784 found that when appropriate intra-hour transmission scheduling practices are in place, the *Avista* restrictions need not apply to the sale of Energy Imbalance, Generator Imbalance, Operating Reserve-Spinning and Operating Reserve-Supplemental services, because with those scheduling practices in place the existing market power screens for sales of energy and capacity can also be applied to sales of those ancillary services.[5]

3. However, because of the unique technical and geographic requirements associated with Reactive Supply and Voltage Control (under OATT Schedule 2) and Regulation and

[3] *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, 78 Fed. Reg. 46,178 (July 30, 2013), FERC Stats. & Regs. ¶ 31,349 (2013).

[4] *Avista Corp*., 87 FERC ¶ 61,223, *order on reh'g*, 89 FERC ¶ 61,136 (1999) (*Avista*). Outside the markets operated by regional transmission organizations and independent system operators, *Avista* authorizes suppliers who cannot show a lack of market power with respect to certain ancillary services to nevertheless sell such services, subject to certain restrictions. As relevant to this Final Rule, these restrictions prohibit sales to a public utility that is purchasing ancillary services to satisfy its own Open Access Transmission Tariff (OATT) requirements to offer ancillary services to its own customers, or sales to a traditional, franchised public utility affiliated with the third-party seller, or where the underlying transmission service is on the transmission system of the affiliated public utility.

[5] Order No. 784, FERC Stats. & Regs. ¶ 31,349 at P 4, PP 57-58.

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Frequency Response (under OATT Schedule 3),[6] the Commission only allowed market-based rate sales of Schedule 2 and Schedule 3 services to a public utility that is purchasing ancillary services to satisfy its OATT requirements if either: a) the sale is made pursuant to a competitive solicitation that meets certain specified requirements; or b) the sale is made at or below the buying public utility transmission provider's own Schedule 2 or 3 rate, as applicable. The Commission further stated its intention to gather more information regarding the technical, economic and market issues concerning the provision of these services in a separate proceeding.

4. Commission staff held a workshop on April 22, 2014 in this proceeding and then issued a notice of proposed rulemaking that distinguished between regulation service and primary frequency response service, and proposed to allow sales of primary frequency response service at market-based rates by entities granted market-based rate authority for sales of energy and capacity.[7] In response to the NOPR, 19 sets of comments were submitted.

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[6] *Id.* PP 59-61. Although the title of Schedule 3 addresses both frequency response and regulation, the two services are distinct from each other. Frequency response is a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over while regulation service is centrally dispatched through automatic generation control (AGC) and is not focused exclusively on frequency control.

[7] *Third-Party Provision of Primary Frequency Response Service*, Notice of Proposed Rulemaking (NOPR), 80 Fed. Reg. 10,426 (Feb. 26, 2015), FERC Stats. & Regs. ¶ 32,705 (2015).

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I. Background

5. The Commission in Order No. 888[8] delineated two categories of ancillary services: those that the transmission provider is required to provide to all of its basic transmission customers[9] and those that the transmission provider is only required to *offer* to provide to transmission customers serving load in the transmission provider's control area.[10] With respect to the second category, the Commission reasoned that the transmission provider is not always uniquely qualified to provide the services, and customers may be able to more cost-effectively self-supply them or procure them from other entities. The Commission contemplated that third parties (i.e., parties other than a transmission provider supplying ancillary services pursuant to its OATT obligation) could provide these ancillary services on other than a cost-of-service basis if such pricing was supported, on a case-by-case

[8] *See 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).

[9] The first category consists of Scheduling, System Control and Dispatch service and Reactive Supply and Voltage Control from Generation Sources service.

[10] The second category consists of Regulation and Frequency Response service, Energy Imbalance service, Operating Reserve-Spinning service, and Operating Reserve-Supplemental service. Order No. 890 later added an additional ancillary service to this category: Generator Imbalance service. *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 85, *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 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

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basis, by analyses that demonstrated that the seller lacks market power in the relevant product market.[11]

6. Subsequently, in *Avista*,[12] the Commission adopted a policy allowing third-party ancillary service providers that could not perform a market power study to sell certain ancillary services at market-based rates with certain restrictions.[13]

7. As noted earlier, the instant proceeding derives from Order No. 784 in which the Commission found that when appropriate intra-hour transmission scheduling practices are in place, the *Avista* restrictions need not apply to the sale of Energy Imbalance, Generator Imbalance, Operating Reserve-Spinning and Operating Reserve-Supplemental services, because with those practices in place, the results of the existing market power screens for sales of energy and capacity can also be applied to sales of these ancillary services.[14]

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[11] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,720-21.

[12] *See supra* n.4.

[13] These ancillary services included: Regulation and Frequency Response, Energy Imbalance, Operating Reserve-Spinning, and Operating Reserve-Supplemental. The Commission did not extend this *Avista* policy to Reactive Supply and Voltage Control from Generation Sources service, which means that third parties wishing to sell this ancillary service at market-based rates would be required to present specific evidence of a lack of market power in the provision of this specific product before the Commission would authorize sales of this service at market-based rates. The Commission also did not extend the *Avista* policy to Scheduling, System Control and Dispatch service. Because only balancing area operators can provide this ancillary service, it does not lend itself to competitive supply. Order No. 784, FERC Stats. & Regs. ¶ 31,349 at n.17.

[14] Because energy and generator imbalance services merely require the ability to respond to dispatch within the hour, the Commission found that any sub-hourly transmission scheduling interval would be sufficient. Order No. 784-A, 146 FERC ¶ 61,114 at P 12 (2012). As the operating reserve services require more rapid response within the hour (spinning reserves must be available immediately and

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8. However, the Commission also found in Order No. 784 that the record developed to that point did not support expanding these market-based rate authorizations to include sales of Reactive Supply and Voltage Control (under OATT Schedule 2) (Schedule 2 service) and Regulation and Frequency Response (under OATT Schedule 3) services (Schedule 3 service).[15] Instead, the Commission allowed market-based rate sales of Schedule 2 and Schedule 3 services to a public utility that is purchasing ancillary services to satisfy its OATT requirements, provided the sale is made pursuant to a competitive solicitation that meets certain specified requirements[16] or the sale is made at or below the buying public utility transmission provider's own Schedule 2 or 3 rate, as applicable.[17] The Commission further stated its intention to gather more information regarding the technical, economic and market issues concerning the provision of these services in a separate proceeding that considers, among other things, the ease and cost-effectiveness of relevant equipment upgrades, the need for and availability of appropriate special

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supplemental reserves must be available within a short period of time), the Commission required potential sellers of operating reserve services to satisfactorily explain, in their market-based rate applications, how the particular intra-hour transmission scheduling practices or other protocols in their regions permit resources in one balancing authority area to respond to contingencies in a neighboring balancing authority area within these tight time frames. Order No. 784-A, 146 FERC ¶ 61,114 at PP 13-15.

[15] Order No. 784, FERC Stats. & Regs. ¶ 31,349 at PP 59-61.

[16] *Id.* PP 99-101.

[17] *Id.* PP 82-85.

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arrangements such as dynamic scheduling or pseudo-tie arrangements, and other technical requirements related to the provision of Schedule 2 and Schedule 3 services.[18]

9. Pursuant to that directive, Commission staff held a workshop on April 22, 2014 to obtain input from interested persons regarding the technical, economic and market issues concerning the provision of Schedule 2 and Schedule 3 services.[19] Among other things, the workshop explored issues surrounding the sale of these services at market-based rates. Comments submitted in response to the workshop that discussed the characteristics associated with a primary frequency response product indicated that market-based rate sales of such a product are feasible.[20]

10. Separately, the Commission on January 16, 2014 issued a Final Rule approving reliability standard BAL-003-1[21] under which a balancing authority[22] must maintain a

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[18] *Id.* P 61.

[19] *See Third-Party Provision of Reactive Supply and Voltage Control and Regulation and Frequency Response Services*, Final Agenda, Docket No. AD14-7-000 (Apr. 22, 2014).

[20] For example, most commenters echo Edison Electric Institute's (EEI) arguments that virtually all generators can provide primary frequency response, and because it is provided at the interconnection level, balancing authority areas have more flexibility on the location of the resource than they would for other products. *See, e.g.*, Edison Electric Institute Post-Workshop Comments, Docket No. AD14-7-000, at 7-8 (filed June 3, 2014).

[21] Reliability standards proposed by the North American Electric Reliability Corporation (NERC) are subject to the Commission's jurisdiction under section 215 of the Federal Power Act. 16 U.S.C. 824o(d). The Commission has authority to approve or reject such standards, and to enforce those that are approved.

[22] The NERC Glossary 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

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minimum frequency response obligation.[23] While most balancing authorities should be able to meet the new reliability standard using their own resources,[24] some may nevertheless be interested in purchasing primary frequency response service from others if doing so would be economically beneficial.

11. Based upon information received at the workshop and in the subsequently-filed 11 written comments, the Commission issued a NOPR that differentiated between regulation service and primary frequency response service, analyzed the technical characteristics of primary frequency response service to show why the existing market power screens for sales of energy and capacity could be used to show lack of market power for sales of primary frequency response as well, and therefore proposed to allow sales of primary frequency response service at market-based rates by entities granted market-based rate authority for sales of energy and capacity.[25] The NOPR sought comment on all aspects of this proposal.[26]

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time." *See* http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[23] *See Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014).

[24] *Id.* PP 62-63.

[25] NOPR, FERC Stats. & Regs. ¶ 32,705 (2015). With respect to the remainder of the issues discussed in the workshop and associated written comments, the Commission did not see sufficient evidence to pursue generic reforms through this rulemaking proceeding. *Id.* P 10.

[26] *Id.* P 30.

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12. Most of the 19 sets of comments submitted in response to the NOPR are supportive of the proposal, with some commenters seeking clarification of various issues. Meanwhile, the limited set of adverse comments fall into two broad categories: 1) comments seeking to contest the technical arguments regarding market power relied upon by the NOPR; and 2) comments that do not relate to market power screening but rather relate to various aspects of the implementation of actual primary frequency response transactions.

13. For the reasons described more fully below, the Commission finds that it is appropriate to finalize the NOPR proposal to permit voluntary sales of primary frequency response service at market-based rates for entities granted market-based rate authority for sales of energy and capacity. We also address various requests for clarification, as discussed more fully below. We emphasize that this Final Rule does not place any limits on the types of transactions available to procure primary frequency response service; they may be cost-based or market-based, bundled with other services or unbundled as discussed further below, and inside or outside of organized markets. This Final Rule focuses solely on how jurisdictional entities can qualify for market-based rates for primary frequency response service in the context of voluntary bilateral sales.

II. Discussion

14. In the NOPR in this proceeding, the Commission proposed to define primary frequency response service as the "autonomous, automatic, and rapid action of a generator, or other resource, to change its output (within seconds) to rapidly dampen large changes in

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frequency."[27] Elsewhere in the NOPR, the Commission discussed the idea that individual autonomous responses to large changes in frequency will be of short duration, sustained only until dispatched regulation or operating reserve resources begin responding.[28] As there are aspects of both statements that are important to properly defining this product, in this Final Rule the Commission will refine and clarify the NOPR's definition to state that primary frequency response service is defined as a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over.

A. Technical Issues Related to the Application of Existing Market Power Screens to Primary Frequency Response Service

1. Geographic Market and the Impact of Resource Distance

15. The Commission analyzes horizontal market power for market-based sales of energy and capacity[29] using two indicative screens, the wholesale market share screen and the pivotal supplier screen, to identify sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority.[30] The

[27] *Id.* P 12.

[28] *Id.* P 24.

[29] *See* 18 CFR 35.37(b) (2015).

[30] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 13, 62, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305

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wholesale market share screen measures whether a seller has a dominant position in the relevant geographic market in terms of the number of megawatts of uncommitted capacity owned or controlled by the seller, as compared to the uncommitted capacity of the entire market.[31] A seller whose share of the relevant market is less than 20 percent during all seasons passes the wholesale market share screen.[32] The pivotal supplier screen evaluates the seller's potential to exercise horizontal market power based on the seller's uncommitted capacity at the time of annual peak demand in the relevant market.[33] A seller satisfies the pivotal supplier screen if its uncommitted capacity is less than the net uncommitted supply in the relevant market.[34]

16. Passing both the wholesale market share screen and the pivotal supplier screen creates a rebuttable presumption that the seller does not possess horizontal market power; failing either screen creates a rebuttable presumption that the seller possesses horizontal market power.[35] A seller that fails one of the screens may present evidence, such as a

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(2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied*, 133 S. Ct. 26 (2012). *See also* 18 CFR 35.37(b), (c)(1) (2015).

[31] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 43.

[32] *Id.* PP 43-44, 80, 89.

[33] 18 CFR 35.37(c)(1) (2015).

[34] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 42.

[35] 18 CFR 35.37(c)(1) (2015).

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delivered price test, to rebut the presumption of horizontal market power.[36] In the alternative, a seller may accept the presumption of horizontal market power and adopt some form of cost-based mitigation.[37]

17. Three of the key components of the analysis of horizontal market power are the definition of products, the determination of appropriate geographic scope of the relevant market for each product, and the identification of the uncommitted generation supply within the relevant geographic market. In Order No. 697, the Commission adopted a default relevant geographic market for sales of energy and capacity.[38] Specifically, the Commission generally uses a seller's balancing authority area plus directly interconnected (first-tier) balancing authority areas, or uses the Regional Transmission Organization (RTO) or Independent System Operator (ISO) market if applicable, as the default relevant geographic market. However, where the Commission has made a specific finding that there is a submarket within an RTO/ISO, that submarket becomes the default relevant

[36] 18 CFR 35.37(c)(2) (2015). For purposes of rebutting the presumption of horizontal market power, sellers may use the results of the delivered price test to perform pivotal supplier and market share analyses and market concentration analyses using the Herfindahl-Hirschman Index (HHI). The HHI is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in the market and summing the results. The Commission has stated that a showing of an HHI less than 2,500 in the relevant market for all season/load periods for sellers that have also shown that they are not pivotal and do not possess a market share of 20 percent or greater in any of the season/load periods would constitute a showing of a lack of horizontal market power, absent compelling contrary evidence from intervenors. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 111.

[37] 18 CFR 35.37(c)(3) (2015).

[38] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 15.

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geographic market for sellers located within the submarket for purposes of the market-based rate analysis. The Commission also provided guidance as to the factors the Commission will consider in evaluating whether, in a particular case, to adopt an alternative larger or smaller geographic market instead of relying on the default geographic market.[39]

18. The Commission stated in the NOPR that, because primary frequency response service can be effectively supplied by any resource throughout an interconnection and have the same ability to dampen harmful changes in interconnection-wide frequency, the geographic market for market power analysis of a primary frequency response product could be the entire interconnection within which the buyer resides, and in any event would be no smaller than the geographic market represented in the existing market power screens;[40] i.e., the home balancing authority area of the seller plus first-tier balancing authority areas or the RTO/ISO market if applicable. The Commission therefore proposed to apply the existing market power screens used for energy and capacity sales, without modification as to geographic market, to sales of primary frequency response service.

[39] A necessary condition that must be satisfied to justify an alternative market is a demonstration regarding whether there are frequently binding transmission constraints during historical peak seasons examined in the screens and at other competitively significant times that prevent competing supply from reaching customers within the proposed alternative geographic market. *Id.* P 268.

[40] NOPR, FERC Stats. & Regs. ¶ 32,705 at P 23.

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19. Most commenters either express specific support for this finding,[41] or are silent on the issue.[42] However, American Public Power Association, the National Rural Electric Cooperative Association, and the Transmission Access Policy Study Group (together, TAPS), PJM Interconnection, L.L.C. (PJM), and Midcontinent Independent System Operator, Inc. (MISO) raise limited, technical concerns regarding this finding.

20. TAPS argues that while remote generators may be capable of responding, there is reason to be concerned that frequency response from a distant generator would be less effective than frequency response from a nearby generator, and that this alleged impact of distance would upset the Commission's proposal to rely on the existing market-based rate screens used for energy and capacity sales to ensure that sellers of primary frequency response service lack market power when making sales to public utility transmission providers.[43]

21. PJM similarly asserts, without elaboration, that questions remain as to whether there is sufficient substitutability of units across the Eastern Interconnection so as to support the conclusion that market power issues are of limited concern in the provision of primary frequency response. PJM also asserts that the kind of communications

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[41] *See, e.g.*, American Wind Energy Association (AWEA) at 6; Calpine Corporation (Calpine) at 5; EEI at 2; Electricity Consumers Resources Council (ELCON) at 3.

[42] *See* Dominion Resources Services, Inc. (Dominion) at 2; Duke Energy Corporation (Duke) at 3; Electric Power Supply Association (EPSA) at 3; Energy Storage Association (ESA) at 1; Idaho Power Company (Idaho Power) at 2; Public Interest Organizations at 2.

[43] TAPS at 5-6.

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infrastructure, protocols, and compensation policies necessary to permit PJM to obtain primary frequency response from resources outside of its market do not yet exist.[44]

22. MISO argues that, while the NOPR is correct that any resource anywhere in an interconnection can help stabilize the frequency of that interconnection following a load or resource loss, there may be negative reliability impacts caused by flows to very remote locations, particularly if there are weak or transmission-limited interfaces.[45]

Commission Determination

23. We adopt the NOPR proposal to apply the existing market power screens used for energy and capacity sales, without modification as to geographic market, to sales of primary frequency response service. With respect to TAPS's arguments, the Commission finds that the delay in sensing a change in frequency associated with resource distance does not undermine the NOPR's proposal to rely upon the default geographic market reflected in the existing market power screens for sales of energy and capacity; i.e., the home balancing authority area of the seller plus first-tier balancing authority areas or the RTO/ISO market if applicable. While TAPS is correct that a resource located far across an interconnection from the site of a contingency event should sense the resulting change in frequency later than would a closer resource, studies of this issue[46] indicate that this

[44] PJM at 4.

[45] MISO at 5.

[46] *See, e.g.*, http://fnetpublic.utk.edu/eventsamples/20110823175058_E.jpg. *See also*, John Undrill, *Power and Frequency Control as it Relates to Wind-Powered Generation* (2010), *available at* http://www.ferc.gov/CalendarFiles/20110120114503-Power-and-Frequency-Control.pdf.

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delay would be within the NOPR's product definition that requires primary frequency response resources to change their output within seconds in response to a large change in frequency.[47]

24. With respect to PJM's assertion that questions remain as to the substitutability of units across the Eastern Interconnection, PJM has not explained what those questions may be, and in any event the NOPR does not propose to test market power based on an interconnection-wide geographic market.

25. With respect to PJM's argument that the kind of communications infrastructure, protocols, and compensation policies necessary to permit PJM to obtain primary frequency response from resources outside of its market do not yet exist, the Commission partially agrees and partially disagrees as described below, but even where we partially agree, this would not impact the NOPR proposal regarding market power screening.

26. With respect to communications protocols, the Commission agrees that in order to effectuate actual voluntary primary frequency response transactions, it may be necessary to further develop or refine existing communications protocols, as more detailed data may be needed for purposes of verifying primary frequency response activity than for other activities. However, this refinement should not pose such a fundamental barrier to sales of primary frequency response service from one balancing authority area to another that it calls into question the default geographic market of the existing market power screens. This is because, as will be discussed further below, there are existing information sharing

[47] NOPR, FERC Stats. & Regs. ¶ 32,705 at P 12.

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systems and protocols that should be able to accommodate the more detailed information associated with primary frequency response transactions without requiring an unreasonable amount of effort from affected parties. Hence, for market power screening purposes, resources in first-tier balancing authority areas should remain viable competitors to supply primary frequency response to the home balancing authority area.

27. With respect to compensation policies, the Commission disagrees with PJM that compensation policies necessary to support this Final Rule do not yet exist. As will be further discussed below, this Final Rule does not require development of organized markets for primary frequency response service, but rather is focused on voluntary bilateral sales of primary frequency response at market-based rates. In bilateral markets, compensation would be negotiated between the buyer and the seller pursuant to the seller's market-based rate authority. As such, bilateral transactions will be strictly voluntary and the buyer will presumably only agree to them if it sees an economic reason to do so. Therefore, no further compensation policies are necessary in connection with this Final Rule.

28. Finally, MISO argues that there may be negative reliability impacts caused by flows to very remote locations, particularly if there are weak or transmission-limited interfaces. The Commission agrees but sees this as a practical consideration relevant to particular bilateral transactions rather than a universal issue that invalidates the use of existing market power screens to show lack of market power for sales of primary frequency response service. Accordingly, this argument does not invalidate the NOPR proposal regarding market power screening for sellers of primary frequency response service.

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2. Need for Transmission Reservation and Scheduling

29. With respect to potential barriers related to transmission scheduling or reservation, the Commission stated in the NOPR that primary frequency response service should not require any transmission reservation or scheduling, because by definition individual frequency responses would not be sustained for long enough periods to trigger a need for transmission service or schedule changes. Rather, such individual primary frequency responses should be rapidly replaced by resources centrally dispatched by the relevant balancing authority.[48]

30. Most commenters either specifically agree that transmission scheduling and reservation should not be necessary in connection with the temporary, autonomous changes in output associated with primary frequency response service,[49] or remain silent on the issue. However, EEI asserts that transmission reservation or scheduling may be needed in some cases. According to EEI, the duration of primary frequency response products could range from a minute or two to supplement a response for only large events, to an unbounded number of minutes for as long as frequency remains beyond a given frequency deadband. In the case of longer durations, according to EEI, transmission providers may have to assess the potential transmission impact of third-party resources

[48] NOPR, FERC Stats. & Regs. ¶ 32,705 at P 24.

[49] *See, e.g.*, AWEA at 6; ELCON at 3; MISO at 1.

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providing primary frequency response through their service territory for extended periods of time.[50] Duke makes similar arguments.[51]

31. Similarly, TAPS argues that the Commission did not adequately examine in the NOPR the implications of remote provision of primary frequency response on transmission availability and co-optimization of energy and ancillary services. TAPS argues the Commission should provide additional analysis of how remote supply of frequency response service will affect transmission reserve margin and available transfer capability, how the associated costs are borne, and whether this will have adverse consequences for market efficiency, particularly in RTOs.[52]

Commission Determination

32. The Commission continues to believe that transmission reservation and scheduling will not create a barrier to sales of frequency response within an interconnection. While the Commission concedes that in some cases transmission capacity may need to be reserved to support a sale of primary frequency,[53] we continue to believe that in the vast majority of cases the sale of primary frequency response service should not require any

[50] EEI at 8.

[51] Duke at 7-8.

[52] TAPS at 9-11.

[53] The Commission expects that sales of primary frequency response from resources in transmission constrained areas would constitute the most likely scenario where a reservation of transmission capacity might be needed to support the sale. Naturally, the added cost of such transmission purchases would likely be considered by the potential purchaser in deciding whether or not to enter into such purchase.

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transmission reservation or scheduling because, by definition, individual frequency responses would not be sustained for long enough periods to trigger a need for transmission service or schedule changes. With respect to EEI's arguments, the Commission disagrees that primary frequency response, as defined in this Final Rule, could last for an unbounded number of minutes. By the definition of primary frequency response provided in this Final Rule, individual primary frequency responses shall be short, lasting only until dispatched resources can take over. Thus, even if a deviation from target frequency lasts longer than the typical short responses envisioned by our primary frequency response product definition, this does not necessarily mean that a particular resource that continues to respond to that deviation is doing so through extended periods of primary frequency response service as EEI suggests.

33. Rather, after the initial autonomous response, any continuing response would be deemed to occur as a result of dispatch instructions from the relevant balancing authority, which would most likely constitute either use of regulation or operating reserves. Accordingly, while a transmission reservation may sometimes be needed to support a sale of primary frequency response, there should never be a need to actually schedule transmission or change a transmission schedule in connection with primary frequency response service. Hence, transmission scheduling should pose no barrier to sales of primary frequency response service, and in the open access transmission environment created by Order No. 888, reservation by itself does not present any undue barrier to participation. Indeed, all other ancillary service transactions, at least in bilateral markets, are expected to include needed transmission reservation.

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34. With respect to TAPS's argument, the Commission agrees that transmission providers may in some cases need to set aside additional transmission capacity to support particular sales of primary frequency response from remote resources. However, the possibility that particular transactions involving remote resources may require additional transmission capacity to be set aside does not undermine the NOPR proposal to grant market-based rate authority for voluntary sales of primary frequency response to entities that pass the existing market power screens for sales of energy and capacity. These screens already limit consideration of imports from first-tier balancing authority areas based on simultaneous transmission import limits as a way to test market power under realistic conditions based on a reasonable simulation of historical conditions.[54] No further consideration of transmission impacts is necessary to test for seller market power. Analysis of (1) how remote supply of primary frequency response service in particular transactions might affect transmission reserve margin and available transfer capability; (2) how the associated costs would be borne; or (3) whether this might have adverse consequences for market efficiency are concerns that are not relevant to the Commission's market power assessment. Rather, these are concerns that may impact a balancing authority's decision as to whether to enter into any given primary frequency response transaction, or that may become relevant if any RTO or ISO voluntarily chooses to develop an organized market for primary frequency response - something that is not required by this Final Rule.

[54] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354.

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35. With respect to TAPS's arguments regarding potential distortion of co-optimized RTO/ISO energy and ancillary service markets, this Final Rule merely clarifies the appropriate method for ex ante market power screening for potential sellers of primary frequency response service. It does not require any entity, including RTOs and ISOs, to purchase primary frequency response. Nor does it require RTOs and ISOs to develop organized markets for primary frequency response. The Commission finds it reasonable to assume that if an RTO or ISO ever decides to purchase primary frequency response service, it will only do so if the RTO or ISO can address its and its stakeholders' concerns as to the impact on its co-optimized markets. Furthermore, if such purchases require any tariff modifications, the RTO or ISO would also need to submit a filing to the Commission for its review addressing such issues. Accordingly, in the context of this Final Rule focusing on market power screens, these concerns are premature and beyond the scope.

B. Requests for Clarification

1. Purchases Required or Optional

36. A variety of entities request clarification that this Final Rule does not require purchases of primary frequency response or the development of organized markets for primary frequency response.[55] At the other end of the spectrum, Calpine argues that RTOs and ISOs should be given a deadline to develop tariff changes that would enable them to implement primary frequency response compensation mechanisms.[56]

[55] EEI at 1-2; California Independent System Operator Corporation (CAISO) at 2; MISO at 1; PJM at 2, 5.

[56] Calpine at 9.

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37. The Commission grants the requests to clarify that this Final Rule does not require any entity to purchase primary frequency response from third parties or to develop an organized market for primary frequency response. This Final Rule is limited to issues associated with market power screening for voluntary bilateral sellers of primary frequency response service. In light of this clarification, we deny Calpine's request for RTOs and ISOs to be given a deadline to develop tariff changes that would enable them to implement primary frequency response compensation mechanisms.

2. Interaction with Regulation Service

38. EEI and Duke both request that sellers be able to retain the reference to "Regulation and Frequency Response Service" in their current market-based rate tariffs, and that the Final Rule make clear that providing market-based rate authorization for primary frequency response service is not intended to limit the options that buyers have in procuring these ancillary services.[57]

39. The Commission does not intend to limit the options that buyers have in procuring these ancillary services but will nevertheless affirm the NOPR proposal to require a separate listing of regulation service and primary frequency response service in market-based rate tariffs. However, to address EEI's and Duke's concerns, the Commission clarifies that, even though we require that regulation service and primary frequency response service be separately listed in sellers' market-based rate tariffs, this does not mean that buyers and sellers cannot agree to combined transactions involving both

[57] EEI at 4; Duke at 3-7.

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regulation service and primary frequency response service with appropriate restrictions. Those restrictions involve the need for the market-based regulation service component to be limited to the buyer's OATT rate for regulation or the outcome of a competitive solicitation as described in Order No. 784.[58] No such restrictions would apply to the primary frequency response service component of such combined transactions.

40. Duke also expresses concern as to what impact splitting the services in the "Third Party Provider" section of the market-based rate tariff would have on transmission providers and any transmission customers self-providing service under Schedule 3 of the OATT.[59]

41. The Commission clarifies that OATT Schedule 3 serves a different purpose from the market-based rate tariff (cost-based sales from the OATT provider versus market-based sales from third parties), and so OATT Schedule 3 does not need modification as a result of this Final Rule. However, to the extent that a particular OATT provider purchases primary frequency response from a third party in order to help serve its OATT customers, it may propose in a section 205 filing to include such costs in its OATT Schedule 3 rates.

[58] Order No. 784, FERC Stats. & Regs. ¶ 31,349 at PP 82 and 99-101.

[59] Duke at 6, 8.

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3. Information Sharing and Measurement and Verification

42. A variety of entities emphasize the importance of adequate information sharing and measurement and verification if primary frequency response service is to be traded.[60] In this regard, SmartSenseCom, Inc. (SmartSenseCom) also argues that in order to support the broadest base of available resources to provide primary frequency response services, potential providers should have flexibility in their ability to select any monitoring device that meets or exceeds applicable industry standards for accuracy as a means to measure frequency and trigger the primary frequency response at a given set point.[61]

43. The Commission agrees that these matters are important, and expects that potential buyers will ensure that the resources from which they purchase are capable of providing the service in a useful manner, consistent with relevant NERC requirements and guidelines as discussed earlier. This would require that, among other things, the parties agree to appropriate information sharing and measurement and verification. At this stage, and given the voluntary nature of any primary frequency response transactions that may result from this Final Rule, the Commission sees no need to be more prescriptive regarding specific methods of information sharing and measurement and verification.

44. In a related matter, TAPS asserts that the NOPR's statement that telemetry sharing should not pose any significant barrier to the use of remote resources for the purposes of market-based rates requires further evaluation. TAPS argues that transmitting the

[60] CAISO at 2-3; EEI at 5; MISO at 1-4; Duke at 7-8; Dominion at 3; Idaho Power at 2.

[61] SmartSenseCom at 9-10.

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telemetry data from one balancing authority area to just one other balancing authority area effectively doubles (or more) the number of points at which the data can be intercepted or attacked. Thus, TAPS argues that the Commission should provide additional analysis to evaluate whether these potential technical barriers will impede the ability of remote generators to compete to make market-based rate sales of primary frequency response across balancing authorities and to multiple balancing authorities.[62]

45. As mentioned earlier, the Commission finds that balancing authorities already share with their neighbors the same type of operational information contemplated here, both on a day-to-day basis, and occasionally through special arrangements like pseudo-ties or dynamic schedules, though they may not do so with as much detail as would be required for primary frequency response. In sharing such information, they use secure protocols such as Inter-Control Center Communications Protocol.[63] There appears to be nothing unique about information related to primary frequency response transactions, which would largely involve the real-time operational state of the resources in question as a way of verifying both their readiness to respond and actual responses to relevant frequency deviations, that could not be accommodated by this existing secure protocol widely used by the electric utility industry. As a result, the Commission continues to believe that the information sharing required to facilitate sales of primary frequency response service will

[62] TAPS at 6-9.

[63] *See* International Electroctechnical Commission, *Telecontrol equipment and systems - Part 6-802: Telecontrol protocols compatible with ISO standards and ITU-T recommendations - TASE.2 Object models* (Sept. 2005), *available at* https://webstore.iec.ch/publication/18156.

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not create a barrier to such sales and thus we find in this Final Rule that the market power screens used for energy and capacity are valid for primary frequency response service.

4. Definition of Primary Frequency Response Service

46. Parties request various clarifications regarding the definition of primary frequency response service. Calpine and EPSA assert that the product definition for primary frequency response service should include both inertial response from conventional "spinning mass" generators and primary frequency response from discretionary turbine-governor settings.[64] Similarly, Union of Concerned Scientists argues for the inclusion of synchronous and/or synthetic inertia as a market product that can be used to provide primary frequency response, and requests that the Commission clarify whether the creation of markets for inertia is within the scope of changes that were envisioned by the Commission when it issued this NOPR.[65]

47. The Commission emphasizes that this Final Rule addresses market-based rate authority for sales of services that fit the definition of primary frequency response services, i.e., resources standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over. True inertia, while also serving an important function, does not fit this definition because it does not arrest large changes in frequency, but rather acts to oppose all changes in frequency. The term "synthetic inertia" is more complicated to address because it is not

[64] Calpine at 7, n.16; EPSA at 5.

[65] Union of Concerned Scientists at 8.

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clear from the record whether there is actual industry consensus on what the term means. However, if it is assumed to mean a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over, then the Commission would simply consider it a form of primary frequency response subject to this Final Rule. In contrast, if the "synthetic inertia" response either cannot be sustained until dispatched resources take over, or is merely aimed at slowing all changes in frequency instead of arresting large changes, then "synthetic inertia" would not be a form of primary frequency response, and sales of it would not be encompassed by this Final Rule.

48. Several commenters assert that the product definition must differentiate based on response time in addition to magnitude of response.[66] Consistent with this idea, SmartSenseCom asks the Commission to amend section 35.28 of its regulations by adding a new paragraph that states the following:

> Primary frequency response in ancillary service markets. Each Commission approved independent system operator or regional transmission organization that has a tariff that provides for the compensation for primary frequency response service must provide such compensation based upon the actual service provided, include a capacity payment that takes into account the speed of primary frequency response-providing resources and a payment for performance that reflects the quantity of primary frequency response provided by a resource in response to a frequency deviation.[67]

[66] Calpine at 7; AWEA at 4; Grid Storage Consulting at 2-4; Public Interest Organizations at 4; SmartSenseCom at 8.

[67] SmartSenseCom at Ex. A.

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49. The Commission finds that the Final Rule's product definition, summarized at the beginning of the discussion section above, already sufficiently incorporates the importance of speed. The Commission finds that no further differentiation based on response time or magnitude is necessary in connection with this Final Rule, which deals only in the appropriate ex ante market power screening of potential sellers of primary frequency response service. For this reason, and because this Final Rule does not require development of organized markets for primary frequency response, the Commission also denies as unnecessary the requested addition to the Commission's regulations related to organized RTO and ISO markets for primary frequency response.

50. Grid Storage Consulting, LLC (Grid Storage Consulting) and Public Interest Organizations argue that the product definition for this service should require response that is immediate, bi-directional, proportional to the frequency deviation, continuous in the sense of not being prematurely interrupted by competing controls or physical limitations, and certain.[68] The Commission clarifies that potential voluntary buyers and sellers of primary frequency response service are free to negotiate any refinements to the basic product definition in this Final Rule that they see fit, so long as such refinements remain consistent with the basic definition. Obviously, any market-based rate authority granted as a result of this Final Rule would only apply to products that are consistent with the definition of primary frequency response service described at the beginning of the discussion section above.

[68] Grid Storage Consulting at 4-7; Public Interest Organizations at 4.

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51. SmartSenseCom urges the Commission to define primary frequency response directly within the Commission's regulations.[69] The Commission denies this request as unnecessary. The Commission's regulations do not include definitions of every particular product subject to its jurisdiction; it is sufficient for such product definitions to be described in relevant Commission orders such as this one.

5. Miscellaneous Requests for Clarification

52. EEI encourages the Commission to make clear in the Final Rule that a potential third-party provider would not be disqualified from competing on the basis that it is interconnected to an affiliated transmission provider. According to EEI, not addressing the affiliate restriction provisions of the *Avista* policy could unnecessarily limit the pool of third-party generators that would be eligible to compete to provide market-based primary frequency response service.[70]

53. EEI's concern relates to the component of the *Avista* restrictions highlighted below:

> (2) to address affiliate abuse concerns, the approach [permitting market-based rate sales of ancillary services without a corresponding market power analysis] will not apply to sales to a traditional, franchised public utility affiliated with the third-party supplier, ***or to sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier***.[71]

54. As the Commission noted in the *Avista* passage quoted above, this second *Avista* restriction was meant to address affiliate abuse. However, EEI's concern that potential

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[69] SmartSenseCom at 3.

[70] EEI at 7.

[71] *Avista Corp*., 87 FERC ¶ 61,223 at n.12 (1999) (emphasis added).

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third-party providers should not be disqualified from competing on the basis that they are interconnected to an affiliated transmission provider appears to be based on an overly broad interpretation of the language highlighted above; i.e., one that would prevent sales that only tangentially involve the affiliated public utility transmission provider's system. While the Commission understands this concern, we do not believe it is justified because the highlighted language targets a much narrower set of circumstances.

55. In particular, in *Ameren Marketing*,[72] the Commission approved a case-by-case request for market-based rates for ancillary services sales by a third-party seller to transmission customers located on the transmission system of the seller's public utility transmission provider affiliate where the seller offered several safeguards to protect against the potential for affiliate abuse.[73] *Ameren Marketing* demonstrates the narrow scope of the Commission's concern related to this *Avista* restriction; namely, third-party sales to customers located on the transmission systems of affiliates. Only in these situations does the second *Avista* restriction apply, and in these situations, we remain willing to consider requests for market-based rate authority for sales of primary frequency response service on a case-by-case basis. In response to EEI's concern, the Commission

[72] *Ameren Energy Marketing Co.*, 95 FERC ¶ 61,448, at 62,626 (2001) (*Ameren Marketing*).

[73] With respect to all three *Avista* restrictions, the Commission expressed its willingness to consider requests for market-based rate authority under the conditions associated with the restrictions on a case-by-case basis. *Avista Corp*., 87 FERC ¶ 61,223 at n.12.

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clarifies that where the customer is not located on the transmission system of the third-party seller's affiliate, this aspect of the *Avista* restrictions does not apply.

56. EEI also recommends that the Commission clarify in the Final Rule that the location of primary frequency response purchases be deemed to be where the customer is located within an interconnection, rather than where the underlying generation resides. According to EEI, this would address a potential ambiguity in how the NOPR proposal is described in paragraph 28 of the NOPR, where the Commission stated that ". . . sellers passing existing market-based rate screens in a given geographic market should be granted a rebuttable presumption that they lack market power for sales of primary frequency response in that market."[74] EEI states that if a generator has passed the Commission's existing market power screens (or if the screens are not required to be submitted based on the location of the generation) for the geographic market in which the buyer is located, then the generator should benefit from the rebuttable presumption that it lacks market power with respect to sales of primary frequency response service throughout the entire interconnection.[75]

57. EEI appears to be concerned that the language in paragraph 28 might be interpreted to mean that market-based rate sales of primary frequency response are only authorized in specific geographic markets. As will be explained next, this would be similar to how market-based rate sales of operating reserves are handled pursuant to Order No. 784, but

[74] EEI at 7 (citing NOPR, FERC Stats. & Regs. ¶ 32,705 at P 28).

[75] *Id.* at 7-8.

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different from how authority for market-based rate sales of energy and capacity is granted. With respect to energy and capacity, the Commission's normal practice is to test for market power in the seller's home balancing authority area, and, if the seller is vertically-integrated, first-tier balancing authority areas, because this is where the seller's market power likely would be greatest. However, the market-based rate authority granted based on passage of these market power screens permits sales anywhere that the seller is capable of transacting. In Order No. 784, the Commission had to depart from this standard practice with respect to market-based rate sales of operating reserves because of the special transmission scheduling practices associated with those services. Order No. 784 required sellers of operating reserves to first demonstrate that the scheduling practices in the regions within which they wish to sell could support sales of operating reserves from one balancing authority area to another, and market-based rate authority for sales of operating reserves would only be granted for regions where such showing was made successfully by the seller.[76] Because primary frequency response is autonomous and individual responses are of short duration, no special scheduling practices would be required. Hence, the Commission finds that market-based rate authority for sales of primary frequency response should be granted on the same basis as sales of energy and capacity; i.e., while market power is tested at the resource's location, authority is granted for sales anywhere the seller is capable of transacting. The Commission, therefore, clarifies the description in paragraph 28 of the NOPR accordingly.

[76] Order No. 784, FERC Stats. & Regs. ¶ 31,349 at P 58.

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58. AWEA, ESA, Union of Concerned Scientists, and Grid Storage Consulting argue that there may be some resources that have been authorized to sell ancillary services at market-based rates but not energy and capacity, or that are otherwise eligible to participate in Commission-authorized and supervised markets. They recommend that any such resources be permitted to sell primary frequency response service at market-based rates as well.[77] In a similar vein, Public Interest Organizations ask the Commission to consider whether there is any class or potential class of emerging resources that sell only ancillary services and not energy or capacity, and if so, whether such resources should be exempted from existing market power screens in exchange for some more appropriate market power analysis.[78]

59. In response to these comments, the Commission clarifies that for resources capable of injecting electric energy onto the interstate transmission grid,[79] authority to sell at market-based rates, even exclusively in organized RTO or ISO markets, is only granted to entities that either pass the existing market power screens for sales of energy and capacity or where any market power concerns have been adequately mitigated. Thus, even if such

[77] AWEA at 4; ESA at 4-5; Union of Concerned Scientists at 3; Grid Storage Consulting at 10.

[78] Public Interest Organizations at 5-6.

[79] Pursuant to section 201(a) of the FPA, the Commission is charged with regulating the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce. 16 U.S.C. § 824(a) (2012). Section 201(b) provides that the Commission shall have jurisdiction over facilities for wholesale sales of electric energy in interstate commerce or for transmission of electric energy in interstate commerce. *Id.* § 824(b). In section 201(e), a public utility is defined as a person who owns or operates facilities subject to the jurisdiction of the Commission. *Id.* § 824(e).

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sellers only sell ancillary services today, their authorization to do so was granted based in part upon either passage of the existing market power screens for sales of energy and capacity or where there was a demonstration that any market power concerns have been adequately mitigated.[80] The only current exception to this rule involves demand response resources. If a third-party seller exclusively uses demand response resources to participate in RTO/ISO markets, it does not need to seek market-based rate authority or place any tariff on file with the Commission, because demand response resources do not inject electric energy onto the interstate transmission grid. However, if it ever markets services from other types of resources that result in it injecting electric energy onto the grid, then it would need market-based rate authority and a tariff on file.[81] Accordingly, all sellers with market-based rate authority using resources that can inject electric energy onto the interstate transmission grid, even if they only sell ancillary services today, are already eligible to make use of the rebuttable presumption related to primary frequency response in this Final Rule. Similarly, sellers exclusively using demand response resources are already exempted from the need to submit market power analyses to gain authorization for their sales, and Public Interest Organizations have provided no reason why any new class of resources should be exempted.

[80] In the event that sellers fail the existing market power screens for the RTO/ISO markets, the Commission allows such sellers to seek to obtain or retain market-based rate authority by relying on Commission-approved RTO/ISO monitoring and mitigation. *See Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 80 FR 67056, (Oct. 30, 2015), 153 FERC ¶ 61,065, at P 28 (2015).

[81] *EnergyConnect, Inc.*, 130 FERC ¶ 61,031, at PP 26-33 (2010).

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60. Union of Concerned Scientists, ESA, and Public Interest Organizations all ask that the Commission clarify that the current Final Rule applies for all resources that can provide primary frequency response.[82] Steel Producers Alliance makes similar arguments, emphasizing that resources other than generators are able to provide primary frequency response service and should be permitted to compete to provide the service.[83] The Commission clarifies that this Final Rule applies to jurisdictional market-based rate sellers of primary frequency response service, irrespective of what specific equipment they may choose to use to make such sales.

61. MISO asserts that certain technical statements within the NOPR require limited clarification. First, while MISO agrees with the NOPR that 60 Hertz (Hz) is the target frequency in North America, MISO notes that scheduled frequency may be offset at times to correct time error.[84] Second, in response to the NOPR's description of how each balancing authority's automatic generation control system will issue dispatch instructions to regulation resources to try to return the systems frequency to 60 Hz, MISO argues that typically the contingent balancing authority uses a combination of automatic generation control and contingency reserves for this purpose.[85] The Commission agrees with these

[82] Union of Concerned Scientists at 5; ESA at 2-4; Public Interest Organizations at 2-3.

[83] Steel Producers Alliance at 2-3.

[84] MISO at 5.

[85] *Id.* at 6.

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clarifications, but finds that they do not alter any fundamental underpinning of the NOPR proposal.

62. Union of Concerned Scientists seeks clarification that procurement of, and payment for, primary frequency response service would be allowed if the sale of primary frequency response service under market-based rates were allowed. It suggests that the Commission state that markets for primary frequency response service are allowed, subject to petition by appropriate utilities and approval by the Commission.[86] Union of Concerned Scientists also asks that market eligibility and participation as a seller should not be constrained by disproportionate administrative burdens.[87] The Commission agrees that market-based rate sales by entities that have been granted authorization for such sales are allowed; that is, of course, the object of a market-based rate application. With respect to the authority for potential buyers to purchase primary frequency response service, this Final Rule only involves market power screening of potential sellers. As with most products in voluntary bilateral markets, potential buyers do not need the Commission's permission. Similarly, the Commission clarifies that RTOs and ISOs remain free to develop organized markets for primary frequency response if they so choose, though nothing in this Final Rule requires them to do so, and if they choose to do so, only then will the Commission review such issues as eligibility requirements for participation.

[86] Union of Concerned Scientists at 4.

[87] *Id.* at 3.

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6. Requests Outside the Scope of this Proceeding

63. AWEA and Public Interest Organizations both request that the Commission permit sales of regulation service at market-based rates by entities with authority for market-based rate sales of energy and capacity.[88] AWEA further requests that the Commission: a) explore the role that dynamic transfer capability, or lack thereof, plays in protecting against exertion of market power;[89] b) consider relaxing interconnection standards for resources that only sell ancillary services;[90] and c) consider whether entities in bilateral market areas should be required to develop platforms for the sale of primary frequency response, even if on a limited basis such as through open seasons.[91]

64. Monitoring Analytics, LLC (Monitoring Analytics) notes that, while the NOPR is mainly concerned with the market power screens typically used in connection with authorizations to charge market-based rates, in organized markets like PJM's, such rates are granted in significant part based on the market power mitigation rules of the RTO or ISO. Accordingly, Monitoring Analytics recommends that if PJM develops a market for primary frequency response service, the rules for such market should incorporate the

[88] AWEA at 1, 7-9; Public Interest Organizations at 5.

[89] AWEA at 3.

[90] *Id*. at 4.

[91] *Id*. at 5.

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three pivotal supplier test that is already used for market power mitigation in PJM's other markets.[92]

65. ESA argues that fast responding energy storage resources should be allowed to supply both primary frequency response and regulation services simultaneously. In this regard, ESA asserts that the Commission should not inadvertently create a system where all providers of primary frequency response must provide such service for at least 5-10 minutes until the slowest regulation resources can be brought online.[93] ESA requests that the Commission ensure that ancillary service market designs and procurement mechanisms are reasonably consistent across regions and reflect non-market compensated benefits in the determination of operational needs for particular capabilities, such as fast response.[94]

66. Grid Storage Consulting argues that balancing authorities should not be able to mandate that primary frequency response be provided as part of other market products,[95] and that in some circumstances it may be appropriate to permit the costs of dedicated primary frequency response resources to be recovered in transmission rate base.[96]

67. If an RTO seeks to create an organized market for primary frequency response, then Dominion recommends that the Commission require a market design similar to those used

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[92] Monitoring Analytics at 7.

[93] ESA at 5.

[94] *Id*. at 6.

[95] Grid Storage Consulting at 8-9.

[96] *Id*. at 10-11.

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currently to procure other ancillary services such as regulation and operating reserves. Alternatively, Dominion also supports allowing RTOs to procure primary frequency response at cost-based rates, in a manner similar to how reactive power is procured. Dominion also argues that generators should either be exempt from charges such as operating reserve and balancing energy when deviating from their schedules in order to provide primary frequency response service or their compensation should include credits to offset such charges.[97]

68. SmartSenseCom asserts that there is a difference in value between resources capable of delivering a rapid response to changing frequency and slower-responding units. Accordingly, SmartSenseCom asks the Commission to require public utility transmission providers to take into account the speed and accuracy of primary frequency response resources when determining reserve requirements for primary frequency response, as the Commission did for regulation service in Order No. 784. SmartSenseCom claims this "is particularly necessary in this instance in light of the language set forth in Order No. 784 and in the instant NOPR that distinguishes [primary frequency response] from regulation and the different requirements that will now exist for each service."[98]

69. The Commission finds all of these issues to be beyond the scope of this Final Rule. This Final Rule deals only with market-based pricing for voluntary bilateral primary frequency response sellers. While some of the issues raised above might be relevant in

[97] Dominion at 3.

[98] SmartSenseCom at 8.

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other proceedings,[99] none of the issues raised above is relevant to the topic of market-based rates in voluntary bilateral markets. Accordingly, there is no need to address these issues here.

III. Compliance and Implementation

70. In Order No. 697, the Commission provided standard tariff provisions that sellers must include in their market-based rate tariffs to the extent they are applicable based on the services provided by the seller,[100] including a provision for sales of ancillary services as a third-party provider.[101] The Commission hereby revises the "Third Party Provider" ancillary services provision to change the reference to "Regulation and Frequency Response Service" to "Regulation Service" and to add a reference to "Primary Frequency Response Service." The new language is as follows:

> Third-party ancillary services: Seller offers [include all of the following that the seller is offering: Regulation Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, Operating Reserve-Supplemental, and Primary Frequency Response Service]. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where

[99] For example, if an RTO or ISO eventually proposes to develop an organized market for primary frequency response service, or if the Commission at some point in the future decides to require such development, then several of the issues raised above might become relevant at that stage.

[100] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at Appendix C.

[101] In Order No. 784, the Commission revised the standard third party provider provision to reflect the changes adopted in Order No. 784. Order No. 784, FERC Stats. & Regs. ¶ 31,349 at P 200.

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> the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

71. The Commission finds that a seller that already has market-based rate authority as of the effective date of this Final Rule is authorized as of that date to make sales of primary frequency response service at market-based rates. Such a seller will be required to revise the third-party provider ancillary services provision of its market-based rate tariff to reflect that it wishes to make sales of primary frequency response service at market-based rates. However, while this authorization is effective for sellers with existing market-based rate authority as of the effective date of this Final Rule, in order to reduce their administrative burden, the Commission permits such sellers to wait to file this tariff revision until the next time they make a market-based rate filing with the Commission, such as a notice of change in status filing or a triennial update.

72. As noted in the NOPR, consistent with the existing requirements of Order No. 2001, any entity selling primary frequency response service will need to report such sales in the Electric Quarterly Report,[102] and the Commission will update its Electric

[102] *See Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. &

(continued...)

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Quarterly Report system to include a specific product name option for primary frequency response service.[103]

IV. Information Collection Statement

73. The Paperwork Reduction Act (PRA)[104] 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 regulations require approval of certain information collection requirements imposed by agency rules.[105] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of an agency rule will not be penalized for failing to respond to the collection of information unless the collection of information displays a valid OMB control number.

74. The Commission will submit the revised information collection requirements to OMB for its review and approval. The Commission solicits public comments on its need

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Regs. ¶ 31,127, *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *reh'g denied*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing filing*, Order No. 2001-D, 102 FERC ¶ 61,334, *order refining filing requirements*, Order No. 2001-E, 105 FERC ¶ 61,352 (2003), *order on clarification*, Order No. 2001-F, 106 FERC ¶ 61,060 (2004), *order revising filing requirements*, Order No. 2001-G, 120 FERC ¶ 61,270, *order on reh'g and clarification*, Order No. 2001-H, 121 FERC ¶ 61,289 (2007), *order revising filing requirements*, Order No. 2001-I, FERC Stats. & Regs. ¶ 31,282 (2008).

[103] NOPR, FERC Stats. & Regs. ¶ 32,705 at P 29.

[104] 44 U.S.C. 3501-3520 (2012).

[105] *See* 5 CFR 1320 (2015).

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for this information, whether the information will have practical utility, the accuracy of burden and cost estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

75. Burden Estimate and Information Collection Costs: While, to the Commission's knowledge, no entity currently sells primary frequency response service on an unbundled basis,[106] there is no reason why primary frequency response service could not be sold today under cost-based rates. Such cost-based sales, if they occurred, would face all of the burdens associated with cost-of-service regulation, including a variety of requirements from which market-based rate sellers frequently seek and are granted waiver.[107] Furthermore, just like market-based rate sellers, cost-based rate sellers must report all transactions in the Electric Quarterly Report. Accordingly, the Commission views this Final Rule as providing potential market-based rate sellers of primary frequency response

[106] It is likely that some customers purchase primary frequency response service along with other services on a bundled basis, such as through full requirements contracts, but this Final Rule is focused on unbundled sales of primary frequency response service.

[107] Such burdens would include, for example, the need to maintain Open Access Transmission Tariffs and Open Access Same-Time Information Systems related to any jurisdictional transmission facilities owned by the entity, the need to adhere to the Commission's standards of conduct, the need to adhere to the detailed cost-of-service related requirements of subparts B and C of Part 35 of the Commission's regulations, the need to adhere to the accounting and reporting requirements of Parts 41, 101, and 141 of the Commission's regulations, and the need to seek separate authorizations for issuances of securities and assumptions of liabilities under FPA section 204 and Part 34 of the Commission's regulations.

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service with the opportunity to avoid cost-of-service regulation for such sales and the associated substantial reporting burdens.

76. Below, we discuss the expected increases in burden as a result of this Final Rule. The Commission expects the additional burden to be greatly outweighed by the reduction in burden from avoiding cost-of-service regulation. The additional estimated annual public reporting burdens and costs for the requirements in this Final Rule are as follows.

Changes in Final Rule in RM15-2[108]					
Number of Respondents (a)	**Annual Number of Responses per Respondent (b)**	**Total Number of Responses (a)X(b)=(c)**	**Average Burden & Cost Per Response (d)**	**Total Annual Burden Hours & Total Annual Cost (c)X(d)=(e)**	**Cost per Response (e)/(c)**
FERC-516 (Electric Rate Schedules and Tariff Filings) (one time, phased in)					

[108] For purposes of burden estimation, the NOPR assumed that industry staff members are similarly situated to FERC, in terms of hourly cost per full time employee, and no commenter disputes this assumption. Therefore, the estimated average hourly cost (salary plus benefits) is $72.00.

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1,585[109]	0.163[110]	259	6 hrs.; $432	1,554 hrs.; $111,888	$432
FERC-920 (Electric Quarterly Report) (one-time, phased in)					
1,585	0.163 [111]	259	2 hrs.; $144	518 hrs.; $37,296	$144

[109] The 1,585 respondent universe includes existing sellers (1,999 total market-based rate sellers - 697 Category 1 sellers + 70 Category 1 sellers = 1,372 sellers estimated to sell primary frequency response services) plus 213 new market-based rate applicants (as estimated in Docket No. RM14-14). (We estimate that ten percent (or 70, as indicated above) of the Category 1 sellers may choose to sell primary frequency response services.)

[110] We expect respondents to enter the primary frequency response market gradually. For each of the next three years, we expect all 213 new market-based rate applicants per year (or 639 total during Years 1-3), to include the primary frequency response language in their tariffs.

Additionally, during the three-year period, we expect a total of ten percent of the existing 1,372 respondents (or 137 respondents), to decide to sell primary frequency response services and to make the corresponding FERC-516 rate filing. The corresponding annual estimate is 46 of the existing respondents (an average of 3.4% annually). Therefore, the annual estimate, including both new respondents and existing respondents, is an average of 259 (213 + 46) respondents and responses per year.

[111] As respondents decide to sell primary frequency response services, they would report the new offering in their Electric Quarterly Report (FERC-920), and would continue to report in subsequent EQRs. When a filer adds the new service, we estimate the one-time burden to be two hours. We expect any additional burden associated with reporting the new service in the EQR to be negligible after the first implementation as it would become part of the respondent's normal reporting practice in the EQR and would only involve selecting the 'primary frequency response' option from a list of product names. On average, we expect filers of the new primary frequency response service to phase in:

- Year 1, 259 respondents or 16.3 percent of EQR filers.
- Year 2, 259 respondents or 16.3 percent of EQR filers.
- Year 3, 259 respondents or 16.3 percent of EQR filers.

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Titles: FERC-516 (Electric Rate Schedules and Tariff Filings) and FERC-920 (Electric Quarterly Report (EQR)).

Action: Revision of Currently Approved Collection of Information.

OMB Control Nos.: 1902-0096 (FERC-516) and 1902-0255 (FERC-920).

Respondents: Public utilities.

Frequency of responses: One-time, phased in (for both FERC-516 and FERC-920).

Necessity of the Information: Regarding FERC-516, section 205(c) of the Federal Power Act requires public utilities to file with the Commission schedules showing all rates and charges for any transmission or sale subject to the Commission's jurisdiction. Accordingly, entities wishing to sell primary frequency response service at market-based rates must amend their market-based rate tariffs to include the language included in this Final Rule. Regarding FERC-920, the Commission is revising the EQR to ensure that public utilities that may sell primary frequency response service at market-based rates report those sales in the EQR, consistent with their filing obligations under section 205(c).

Internal Review: The Commission has reviewed the requirements associated with the proposed revisions to the information collections and determined they are necessary to ensure that rates remain just, reasonable, and not unduly discriminatory.

77. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, through internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

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78. 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. Comments on the collections of information and associated burden estimates in the Final 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, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Please refer to OMB Control No. 1902-0096 (FERC-516) and OMB Control No. 1902-0255 (FERC-920).

V. Environmental Analysis

79. 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.[112] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Final Rule 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 subject to

[112] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

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the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classifications, and services.[113]

VI. Regulatory Flexibility Act

80. The Regulatory Flexibility Act of 1980 (RFA)[114] generally requires a description and analysis of proposed and final rules that will have significant economic impact on a substantial number of small entities.

81. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[115] The SBA revised its size standard for electric utilities (effective January 22, 2014) from a standard based on megawatt hours to a standard based on the number of employees, including affiliates.[116] Under SBA's current size standards, the entities with market-based rates which are affected by this Final Rule likely come under the following categories[117] with the indicated thresholds (in terms of number of employees[118]):

- Hydroelectric Power Generation, 500 employees.

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[113] 18 CFR 380.4(a)(15) (2015).

[114] 5 U.S.C. 601-612 (2012).

[115] 13 CFR 121.101 (2015).

[116] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77,343 (Dec. 23, 2013).

[117] 13 CFR 121.201, Sector 22, Utilities.

[118] SBA's regulations at 13 CFR 121.201 state that "[t]he number of employees ... indicates the maximum allowed for a concern and its affiliates to be considered small."

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- Fossil Fuel Electric Power Generation, 750 employees.
- Nuclear Electric Power Generation, 750 employees.
- Solar Electric Power Generation, 250 employees.
- Wind Electric Power Generation, 250 employees.
- Geothermal Electric Power Generation, 250 employees.
- Biomass Electric Power Generation, 250 employees.
- Other Electric Power Generation, 250 employees.

82. The categories for the applicable entities have a size threshold ranging from 250 employees to 750 employees. For the analysis in this Final Rule, we are using the threshold of 750 employees for all categories. We anticipate that a maximum of 82 percent of the entities potentially affected by this Final Rule are small. In addition, we expect that not all of those entities will be able to or will choose to offer primary frequency response service.

83. Based on the estimates above in the Information Collection section, we expect a one-time cost of $576 (including the burden cost related to filing both the tariff and the EQR) for each entity that decides to offer primary frequency response service.

84. The Commission does not consider the estimated cost per small entity to impose a significant economic impact on a substantial number of small entities. Accordingly, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

VII. Document Availability

85. 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.

86. 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.

87. 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.

VIII. Effective Date and Congressional Notification

88. The Final Rule is effective [**INSERT DATE 90 days from publication in FEDERAL REGISTER**]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this Final Rule is not a "major rule" as defined in section 351 of the Small Business Regulatory

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Enforcement Fairness Act of 1996. This Final Rule is being submitted to the Senate, House, Government Accountability Office, and Small Business Administration.

List of subjects in 18 CFR Part 35
Electric power rates; Electric utilities; Reporting and recordkeeping requirements.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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In consideration of the foregoing, the Commission amends Part 35, Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 35 – FILING OF RATE SCHEDULES AND TARIFFS

1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C. § 791a-825r, 2601-2645; 31 U.S.C. § 9701; 42 U.S.C. § 7101-7352.

2. Revise § 35.37 (c)(1) to read as follows:

§ 35.37 Market power analysis required.

* * * * *

(c)(1) There will be a rebuttable presumption that a Seller lacks horizontal market power with respect to sales of energy, capacity, energy imbalance service, generation imbalance service, and primary frequency response service if it passes two indicative market power screens: a pivotal supplier analysis based on annual peak demand of the relevant market, and a market share analysis applied on a seasonal basis. There will be a rebuttable presumption that a Seller lacks horizontal market power with respect to sales of operating reserve-spinning and operating reserve-supplemental services if the Seller passes these two indicative market power screens and demonstrates in its market-based rate application how the scheduling practices in its region support the delivery of operating reserve resources from one balancing authority area to another. There will be a rebuttable presumption that a Seller possesses horizontal market power with respect to sales of energy, capacity, energy imbalance service, generation imbalance service, operating

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reserve-spinning service, operating reserve-supplemental service, and primary frequency response service if it fails either screen.

* * * * *

Document Content(s)

RM15-2-000.DOCX.....1-56

153 FERC ¶ 61,134
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RR15-16-000

ORDER ON 2016 BUSINESS PLANS AND BUDGETS

(Issued November 2, 2015)

1. On August 24, 2015, North American Electric Reliability Corporation (NERC) filed 2016 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, the Commission accepts the 2016 business plans and budgets of NERC, the Regional Entities, and WIRAB, as well as the associated attachments and updates. NERC is authorized to issue billing invoices to fund the fiscal year 2016 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 (RFC); 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. FPA section 215(c)(2)(B) 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 FPA section 215, 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 FPA section 215).[5] Among other things, Order No. 672 set forth 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.

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[2] 16 U.S.C. § 824o (2012).

[3] *North American Electric Reliability Corp*., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[4] 16 U.S.C. § 824o(c)(2)(B).

[5] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[6] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 197.

[7] 18 C.F.R. § 39.4(b) (2015).

B. NERC's 2016 Business Plan and Budget

4. The NERC Application contains NERC's proposed business plan and budget for the year ending December 31, 2016, as well as the proposed business plans and budgets of each of the eight Regional Entities and WIRAB for the year ending December 31, 2016.

5. NERC states that the proposed assessment for the total ERO (i.e., NERC, the Regional Entities, and WIRAB) for 2016 allocable to the United States is $150,501,295, which includes $51,785,828 for NERC funding; $97,666,649 for Regional Entity funding; and $1,048,819 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.

6. In addition to the NERC, Regional Entity, and WIRAB business plans and budgets, the NERC Application includes various attachments: Discussion of Comments Received During Development of NERC's 2016 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 2016 Budgets (Attachment 14); Metrics on NERC and Regional Entity Administrative (Indirect) Costs Based on the 2015 and 2016 Budgets (Attachment 15); and Board of Trustee Remuneration Review (Attachment 16).

II. Notices, Responsive Pleadings, and Deficiency Letter

7. Notice of NERC's August 24, 2015 filing was published in the *Federal Register*, 80 Fed. Reg. 52,471 (2015), with interventions and protests due on or before September 14, 2015.

8. WECC, Tri-State Generation and Transmission Association, Inc. (Tri-State), Idaho Power Company (Idaho Power), and Avista Corporation (Avista) filed timely motions to intervene. WIRAB and Eric Morris filed timely motions to intervene and comments.[9] Avista, Idaho Power, Portland General Electric Company, and Tri-State jointly filed comments (collectively, Joint Commenters). On September 21, 2015, Public Utility District No. 1 of Snohomish County (Snohomish) moved to intervene and file comments

[8] NERC Application at 31, 34-35.

[9] The comments filed by Eric Morris suggest general discontent with NERC and its operations but do not include any actionable requests.

out-of-time. On October 1, 2015, NERC and WECC jointly filed a motion to answer protests and an answer to the comments of Joint Commenters and Snohomish.

9. On September 15, 2015, Commission staff issued a deficiency letter requesting additional information regarding the NERC Application.

10. On September 29, 2015, NERC filed a response to the deficiency letter. Notice of NERC's response was published in the *Federal Register*, 80 Fed. Reg. 60,894 (2015), with interventions and protests due on or before October 13, 2015. On October 9, 2015, Avista, Portland General Electric Company and Tri-State (Answering Parties) filed joint comments on NERC's response to the deficiency letter, combined with a joint motion for leave to answer and an answer to NERC's October 1, 2015 answer.

III. Discussion

A. Procedural Matters

11. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2015), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

12. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2015), the Commission will grant Snohomish's late-filed motion to intervene given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

13. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2015), prohibits an answer to an answer unless otherwise ordered by the decisional authority. We will accept the answers filed by NERC and WECC, and by the Answering Parties because they provided information that has assisted us in our decision-making process.

B. Substantive Matters

1. NERC Application

14. NERC states that it prepared its 2016 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 2016 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.

15. NERC states that its principal goals in 2016 are focused on the following areas: (1) continuing to implement NERC's risk-based strategy, with a focus on a set of current high-priority risk projects focused on risks to the reliability of the bulk electric system from changing resource mix, extreme physical events, cybersecurity threats, protection system misoperations, extreme weather preparedness, and right-of-way clearances; (2) physical and cyber security of the bulk electric system; (3) continuing to implement risk-based compliance monitoring and enforcement operations; (4) implementing the revised bulk electric system definition; (5) continuing to implement a risk-based registration system; and (6) transforming the NERC Reliability Standards to a steady state.[10]

16. NERC states that its 2016 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, which is comprised of Compliance Assurance, Compliance Analysis and Certification and Registration, and Compliance Enforcement; (3) Reliability Assessment and Performance Analysis; (4) Reliability Risk Management, which is comprised of Situation Awareness and Event Analysis; (5) Electricity Sector Information Sharing and Analysis Center (ES-ISAC);[11] and (6) Training, Education, and Operator Certification.[12] For these program areas, NERC describes each program, identifies the program's goals and objectives, and provides the number of full-time equivalent employees (FTEs), as well as the amount budgeted for 2016. NERC also provides 2015 accepted budget data and 2015 year-end projected data for comparison.

17. NERC's proposed total funding requirement for 2016 is $67,502,155, which is an increase of $130,891 (0.2 percent) over NERC's 2015 budget.[13] Without the Cyber Risk Information Sharing Program (CRISP), NERC's budget would increase by $1,885,460 (3.3 percent) over its 2015 budget.[14] NERC's proposed 2016 net funding requirement is $57,081,445 (i.e., total budget less funding from other sources), of which $51,785,828 is

[10] NERC Application at 7.

[11] NERC recently changed the name of the ES-ISAC to the Electricity Information Sharing and Analysis Center.

[12] NERC Application at 3-4.

[13] *Id.* at 19.

[14] *Id.* at 8.

allocated to the United States.[15] The net funding requirement allocated to the United States is an increase of $1,738,988 (3.5 percent) over the 2015 budget proposal.[16] NERC states that its proposed total United States net funding requirement for the ERO enterprise is equivalent to $0.000013 per kWh, based on the aggregate Net Energy for Load of the United States in 2014.[17]

18. NERC states that the proposed 2016 business plan and budget reflects a provision for working capital and operating reserve funding in the amount of $380,490.[18] Finally, NERC proposes a 2016 staffing level of 192.47 FTEs, which is an increase of 0.17 FTEs over the 2015 budget staffing level.[19]

19. NERC states that it received $3,710,000 in penalty monies for the period of July 1, 2014 through June 30, 2015.[20] NERC requests to use $1,439,000 of the penalty monies to reduce 2016 assessments, and allocate the remaining $2,271,000 into the assessment stabilization reserve pursuant to NERC's amended working capital and reserve policy (Reserve Policy) as accepted by the Commission.[21] Accordingly, pursuant

[15] *Id.* at 22, 34. NERC's other funding sources are penalty payments, third-party funding for CRISP, revenue from services and software, testing and workshop fees, and interest. *Id.* at 20-21.

[16] *Id.* at Attachment 2, 8-9.

[17] *Id.* at 21.

[18] *Id.* at 20.

[19] *Id.* at Attachment 2, 15.

[20] NERC received an additional $1,000,000 in penalty monies on July 9, 2014. NERC requested to use this penalty money to offset its assessments for the 2015 fiscal year. Request of the North American Electric Reliability Corp. for Acceptance of 2015 Business Plan and Budget, *et al*. (NERC 2015 Budget Filing), Transmittal Letter at 77-79, North American Electric Reliability Corp., Docket No. RR14-6-000 (filed Aug. 22, 2014). NERC's 2015 budget was accepted by the Commission on October 16, 2015. *North American Electric Reliability Corp.*, 149 FERC ¶ 61,028 (2014).

[21] *North American Electric Reliability Corp.*, 151 FERC ¶ 61,225 (2015); *North American Electric Reliability Corp.*, Docket No. RR15-8-001 (Sept. 18, 2015) (delegated letter order).

to section 1107.4 of the NERC Rules of Procedure, NERC requests an exception to section 1107.2 of the NERC Rules of Procedure to permit the allocation of $2,271,000 in penalty monies to the assessment stabilization reserve, rather than use these monies to reduce assessments in 2016.

2. Deficiency Letter and Response

20. The deficiency letter asked NERC, *inter alia*, to (1) justify deviations between its 2015 budgeted levels and its 2015 year-end projections in several of its program areas, and to the extent necessary, discuss how such deviations relate to the limits and filing requirements under Paragraph 7(b)(ii) of a Settlement Agreement resulting from a Commission staff audit of NERC;[22] and (2) provide further justification for the incremental statutory funding required for the ES-ISAC due to CRISP, and explain why the statutory funding proposed for CRISP is increasing in 2016 while overall user-funding for CRISP is decreasing, compared to 2015.[23]

21. NERC responds, first, that the proposed budgets for each year are generally prepared during the first six to seven months of the preceding year, are approved by the NERC Board of Trustees at a meeting held in early to mid-August of the preceding year, and are filed with the Commission on or about August 24 of the preceding year as required by the Commission's regulations. NERC explains that, by the time of the annual business plan and budget filing with the Commission, the current year budget is more than a year old, and subsequent events and changing demands on NERC's operations often result in variances between the budget for the current year and the currently projected year-end results for the current year. Accordingly, given the long lead time

[22] The terms under Paragraph 7(b)(ii) state that the "requirement for Commission review and approval is triggered if any amount allocated from . . . operating reserves plus any amount re-directed from previously budgeted funds is, in the aggregate, $500,000 or more for any one specific project or major activity in a program area." *North American Electric Reliability Corp.*, 142 FERC ¶ 61,042, at P 7 of attached Settlement Agreement (2013) (Settlement Agreement) (discussing requirements pertaining to NERC transfers of funds from its operating reserve account); *see also North American Electric Reliability Corp.*, 151 FERC ¶ 61,225 at P 18.

[23] In its 2015 business plan and budget filing, NERC provided a table detailing the incremental cost to the ES-ISAC due to CRISP requiring additional statutory funding. NERC 2015 Budget Filing, Attachment 2, Exhibit F at 137-139, North American Electric Reliability Corp., Docket No. RR14-6-000 (Aug. 22, 2014).

between budget preparation and the budget operating year, NERC maintains that "intra-year resource reallocations are neither unusual, nor should they be unexpected."[24]

22. NERC notes that it prepares and reviews quarterly budget variance reports with NERC's Finance and Audit Committee, and that "these reports track actual to budgeted results for each of the categories of funding, expense and fixed assets set forth on NERC's statement of activities which sets forth its overall budget for the current year."[25] NERC further notes that it files these reports with the Commission.

23. NERC states that the variance in FTEs between the 2015 budgeted and year-end projections for individual programs are due to the timing of transfers of open budgeted positions or transfers of existing personnel, and a reduction in the assumed vacancy rate for approved positions. For each of the program areas listed by the Commission in its deficiency letter, NERC details where each FTE was reallocated within NERC through June 2015, and notes that total FTEs during this period remained within NERC's overall approved personnel budget.

24. In response to the deficiency letter question regarding how such reallocations relate to the requirements for Commission review and approval under Paragraph 7(b)(ii) of the Settlement Agreement, NERC maintains that for each of the areas listed in the deficiency letter, no funds were transferred from operating reserves and that total FTEs remained within NERC's overall approved 2015 personnel budget. NERC asserts, as a result, that no filing pursuant to Paragraph 7(b)(ii) was necessary.

25. Responding to the deficiency letter request to provide further justification for the incremental statutory funding required for the ES-ISAC due to CRISP, NERC includes additional detail regarding the incremental costs, and explains that the most significant factor for the decrease in user fees for CRISP is the non-recurrence of one-time startup costs incurred in 2015, which includes a one-time payment of $500,000 to establish a reserve fund for CRISP. In addition, NERC clarifies that costs for ES-ISAC continue to be allocated 50 percent to NERC and 50 percent to participating utilities, and provides additional information to support that clarification.[26]

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[24] NERC Response at 3.

[25] *Id.* at 3 n.4.

[26] *Id.* at 12-13, Attachment 1.

Commission Determination

26. We accept NERC's 2016 business plan and budget. We find that NERC's 2016 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 1107.4 of the NERC Rules of Procedure and allow NERC to allocate $2,271,000 in penalty monies to the 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.

27. While we accept the 2016 budget plan and budget, we disagree with NERC's interpretation of its responsibilities under paragraph 7(b)(ii) of the Settlement Agreement to file with the Commission for review and approval of the transfers of funds of at least $500,000 from one major activity to another during 2015. In its response to the deficiency letter, NERC stated that because no funds were transferred from operating reserves and total FTEs remained within NERC's overall approved personnel budget, NERC was not required to file with the Commission pursuant to paragraph 7(b)(ii) of the Settlement Agreement. However, when reviewing NERC's proposal to amend the Reserve Policy, the Commission directed NERC to clarify that the amended policy requires "that any reallocation and expenditure of budgeted funds, including from the assessment stabilization reserve, is subject to the requirements of Paragraph 7(b)(ii) of the Settlement Agreement."[27] NERC made that clarification, and the Commission accepted it.[28] Thus, NERC's interpretation of when Commission review is required by

[27] *North American Electric Reliability Corp.*, 151 FERC ¶ 61,225 at P 18.

[28] *North American Electric Reliability Corp.*, Docket No. RR15-8-001 (Sep. 18, 2015) (delegated letter order). NERC's current Reserve Policy states that:

> Any reallocation of budgeted funds and/or expenditure of Operating Reserves . . . other than as approved by the NERC Board of Trustees and FERC as part of the company's annual business plan and budget, shall be submitted to FERC for approval in accordance with the terms and conditions of Section 7(b)(ii) of the Settlement Agreement . . . .

Request for Approval of Revisions to NERC's Working Capital and Operating Reserve Policy, Attachment 1, Docket No. RR15-8-001 (Aug. 14, 2015).

Paragraph 7(b)(ii) is more limiting than the language of the provision as applied in the current Reserve Policy.

28. Additionally, we are concerned that NERC may misunderstand what constitutes a "major activity" under Paragraph 7(b)(ii) of the Settlement Agreement. NERC relies on the fact that NERC's total FTEs remained within NERC's overall approved personnel budget, despite reallocating such staff between Program Areas. However, for the purposes of Paragraph 7(b)(ii), NERC and the Commission agreed to the term "major activities" as described in the 2013 Budget Order,[29] and NERC applied this definition in its creation and application of its statutory criteria.[30] Accordingly, any major activity to which NERC applies its statutory criteria falls under the reporting requirements of Paragraph 7(b)(ii).

29. Therefore, we expect NERC to be mindful of its reporting requirements under the Reserve Policy and Settlement Agreement going forward. For the avoidance of doubt, we clarify that for the 2016 budget year and all future budget years, the Commission expects that NERC must submit to the Commission for approval any reallocations of budgeted funds and/or expenditure of operating reserves required by its Reserve Policy and the Settlement Agreement.

3. Regional Entity Business Plans and Budgets

30. NERC's Application includes the 2016 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

[29] Settlement Agreement, 142 FERC ¶ 61,042, at n.5. *See also North American Electric Reliability Corp.*, 141 FERC ¶ 61,086, at P 31 (2012) (2013 Budget Order) ("As NERC explains, 'major activities' recognizes that various activities in a program area can be grouped into categories and the purpose and statutory basis for each such category explained, without the need to describe each activity therein.") (citing Reply Brief of the North American Electric Reliability Corporation at 47-48, Docket No. FA11-21-000 (Sept. 10, 2012)).

[30] *See* NERC Application, Attachment 2, Exhibit B (discussing "how the major activities in NERC's 2016 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."). These written criteria were approved by the Commission in *North American Electric Reliability Corp.*, 143 FERC ¶ 61,052 (2013) (Statutory Criteria Order).

resources to carry out its delegated functions.[31] The Commission finds that each Regional Entity submission reasonably supports the level of expenditures identified in the budgets, and is focused on adequately staffing and funding all of their respective program areas to perform the delegated, statutory functions. Accordingly, the Commission accepts the Regional Entity business plans and budgets. However, we address below the concerns raised by the Joint Commenters, Snohomish, and the Answering Parties concerning WECC's business plan and budget.

a. WECC Business Plan and Budget

i. Comments

31. WIRAB states that it reviewed WECC's 2016 business plan and budget and found that all proposed activities are eligible and appropriate for funding under FPA section 215. WIRAB requests that the Commission approve WECC's proposed 2016 budget.[32]

32. Joint Commenters argue that certain activities performed by WECC are either not delegable to Regional Entities or are not statutory under FPA section 215. Joint Commenters request that the Commission reject NERC's 2016 budget request to the extent the WECC budget attempts to fund non-statutory activities through statutory funding, and direct NERC and WECC to submit a conforming 2016 business plan and budget for approval.

33. Joint Commenters specifically argue that only two discrete functions–the promulgation and enforcement of Reliability Standards–are delegable to Regional Entities.[33] Joint Commenters note that the Regional Entities are not precluded from performing other activities, but assert that any activities performed beyond these two discrete functions must be funded from sources other than statutory section 215 funding.[34]

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[31] NERC Application at 28-29.

[32] WIRAB Comments at 1-2.

[33] Joint Commenters September 14 Comments at 3.

[34] *Id.* at 5 (citing Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 202).

34. Joint Commenters allege that certain activities performed by WECC in its Reliability Assessment and Performance Analysis and Situational Awareness and Infrastructure Security (SAIS) program areas are not statutory under FPA section 215. First, Joint Commenters maintain that many of the goals and deliverables of the Reliability Assessment and Performance Analysis program, which include developing and maintaining a database for production cost and capital cost models and conducting system adequacy analyses and supporting the interconnection-wide transmission expansion planning process, "are traditional planning and operations-based WECC programs that predate the Energy Policy Act of 2005, and therefore predate section 215."[35] Joint Commenters also note that WECC's transmission expansion planning activity aligns with the non-statutory activities of FRCC and SPP.[36]

35. Similarly, Joint Commenters maintain that activities under WECC's SAIS program area are not activities properly delegable to a Regional Entity. Moreover, Joint Commenters note that some WECC activities are potentially duplicative of those performed by Peak Reliability, now acting as the reliability coordinator, such as "maintain[ing] near real-time situational awareness about the conditions and significant occurrences on the Bulk Electric System in the Western Interconnection."[37]

36. Finally, Joint Commenters argue that the Commission should review NERC's 2016 budget request, particularly WECC's budget request, in conjunction with its review of the WECC Delegation Agreement in Docket No. RR15-12-000, given WECC's and NERC's reliance on the Delegation Agreement as approved by the Commission to support the propriety of activities delegated to the Regional Entities.[38]

37. Snohomish argues that the activities of WECC's Transmission Expansion Planning Policy Committee (TEPPC) are not statutory activities, and therefore not eligible for funding under FPA section 215. Snohomish notes that WECC lists the

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[35] *Id.* at 7-8.

[36] *Id.* at 8 n.21.

[37] *Id.* at 9-10 (quoting NERC Application, Attachment 10 at 28).

[38] Snohomish also noted its participation in Docket No. RR15-12-000, and noted its continued belief "that it is more appropriate to include limitation language [regarding non-statutory activities such as energy market activities] in the regional delegation agreement, rather than on a case by case basis through the annual budget and assessment process." Snohomish Comments at 5.

TEPPC's four main functions as follows: (1) oversee and maintain public databases for transmission planning; (2) develop, implement, and coordinate planning processes and policy; (3) conduct transmission planning studies; and (4) prepare interconnection-wide transmission plans. Snohomish argues that the second through the fourth functions are not reliability activities at all, but are commercial activities and not statutory under FPA section 215.[39]

38. With regard to the first function–maintaining public databases for transmission planning–Snohomish states a concern "that making detailed transmission models available to the public is not in the best interest of reliability." Snohomish recommends that "if WECC is the maintainer of a transmission planning database that includes commercial and siting information it should be moved to the Non-Statutory Budget category," and be funded separately.[40]

39. Snohomish also states its concern regarding WECC's activities related to market seams and coordination.[41] Snohomish maintains that WECC should not address this activity, as it is the responsibility of the regional planning organizations, their members, and other market participants. Snohomish points out that other Commission-regulated energy markets are not statutorily funded, and that allowing a Regional Entity to use FPA section 215 funds to administer energy markets would be inconsistent with how other markets are funded. Snohomish notes that it does not object to Regional Entities taking on additional non-statutory activities, including administering a transmission planning process or an energy market, and that some Regional Entities may be well positioned to perform these activities, but that such activities are beyond the scope of the reliability-related activities under FPA section 215.

40. Based on these concerns, Snohomish requests that the Commission direct WECC to move the $111,000 increase for consultant expenses for transmission expansion scenario studies to WECC's non-statutory budget category, and to revise its 2016 budget to separate out the activities of the TEPPC, other transmission planning activities

[39] *Id.*

[40] *Id.*

[41] *Id.* at 8 (citing NERC Application, Attachment 10 at 4).

unrelated to reliability (such as those related to the Commission's Order No. 1000),[42] and any activities related to the administration of a commercial activity like an energy market.

ii. Answers to Comments

41. In their answer to Joint Commenters and Snohomish, NERC and WECC state that the Commission has consistently approved the Reliability Assessment and Performance Analysis and SAIS activities that Joint Commenters call into question.[43] Additionally, NERC and WECC state that WECC has developed written criteria for determining whether a WECC activity may be funded under FPA section 215 that were based on, and essentially identical to, the Commission-approved written criteria developed by NERC.[44] NERC and WECC state that WECC's Reliability Assessment and Performance Analysis and SAIS program areas fit within NERC's Criteria III and V, which assess whether the activity is necessary or appropriate for conducting or disseminating periodic assessments of the reliability of the Bulk-Power System, or whether the activity is required or specified by the provisions of NERC's Rules of Procedure.[45]

42. NERC and WECC also state that the Reliability Assessment and Performance Analysis activities questioned by Joint Commenters, including those of WECC's TEPPC and Market Interface Committee, support the kinds of Reliability Assessment and Performance Analysis activities that are outlined in NERC Rules of Procedure sections 800, 802, 804, and 805.[46]

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[42] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014) (Order No. 1000).

[43] NERC and WECC Answer at 5 (citing *North American Electric Reliability Corp.*, 117 FERC ¶ 61,091, at P 38 (2006) (2007 Budget Order)).

[44] *Id.* at 7 (citing Statutory Criteria Order, 143 FERC ¶ 61,052). NERC includes the WECC written criteria as part of its application in Attachment 2, Exhibit B.

[45] *See* Statutory Criteria Order, 143 FERC ¶ 61,052 at PP 39-41.

[46] NERC and WECC Answer at 7-9.

43. With respect to the SAIS program, NERC and WECC state that WECC's SAIS activities including "maintaining near real-time awareness and assessing risks about the conditions and significant occurrences on the [Bulk-Power System] in the Western Interconnection, with the objective of recognizing conditions and situations that could impact the reliability of the [Bulk-Power System]."[47] WECC explains, however, that it has access to "limited real-time data" and that its role is to understand system issues and to coordinate with relevant parties to discern patterns and risks to the system. NERC and WECC state that WECC performs all situation awareness activities except the reliability coordinator function, which is performed by Peak Reliability.[48]

44. With respect to the concerns raised by Snohomish regarding the activities of the TEPPC, NERC and WECC state that the predominant transmission planning database maintained by TEPPC is the 10-Year Common Case, which describes the loads, generation and transmission topology that are expected to be in place in 10 years' time, and that this 10-Year Common Case is used in production cost simulations suggested by WECC stakeholders to identify potential congestion that could threaten reliability. NERC and WECC state that the TEPPC's activities are "appropriately viewed as assessment activities described in the NERC and WECC Funding Criteria in that they are necessary or appropriate for: (1) the preparation or dissemination of long-term assessments of the reliability and adequacy of the [Bulk-Power System], and (2) awareness of circumstances on the [Bulk-Power System] and contribute to understanding risks to reliability."[49]

45. NERC and WECC state that the activities of the Market Interface Committee focus on the interface of reliability and market operations, and that the Market Interface Committee limits its market interface activities to only those that impact reliability and expressly avoids any market activities that have no reliability implications. NERC and WECC state that the responsibilities of the Market Interface Committee are to consider matters pertaining to the impact of WECC's Reliability Standards, practices, and procedures on the commercial electricity market in the Western Interconnection, and

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[47] *Id.* at 11.

[48] *Id.* at 12.

[49] *Id.* (citing criterion III.A and III.D of NERC Section 215 Criteria for the Reliability Assessment and Performance Analysis Program). *See* NERC Application at Attachment 2, Exhibit B at 110; *see also* Statutory Criteria Order, 143 FERC ¶ 61,052 at PP 39-41.

participate in identifying issues and developing recommendations for regional criteria related to market interface issues.

46. NERC and WECC state that, as with WECC's TEPPC activities, FPA section 215 funding is appropriate for the Market Interface Committee's activities because section 802 of the NERC Rules of Procedure specifies that the scope of Reliability Assessment and Performance Analysis includes "[i]nvestigate, assess, and report on the potential impacts of new and evolving electricity market practices . . . on the adequacy and operating reliability of the Bulk Power Systems." Additionally, NERC and WECC state that the Market Interface Committee's review of a Reliability Standard's impact on the commercial electricity markets in the Western Interconnection is consistent with section 303 of the NERC Rules of Procedure, which requires that Reliability Standards "meet certain market-related objectives, specifically those dealing with competition, market structure, market solutions, commercially sensitive information, and adequacy."[50] NERC and WECC also state that the Market Interface Committee's participation in developing recommendations for regional criteria related to market interface issues is consistent with section 313 of the NERC Rules of Procedure, which allows Regional Entities to develop regional criteria, as described therein.[51]

47. NERC and WECC state that, while the specific activities in WECC's Reliability Assessment and Performance Analysis and SAIS programs may differ from year to year, WECC continues to perform the same types of activities that it has historically performed and that have consistently been approved by the Commission since 2007, both in the regional delegation agreement and business plan and budget filings. Finally, NERC and WECC note that WECC has no intention of undertaking transmission planning obligations under Order No. 1000 or operating an energy imbalance market.

48. In response to NERC's and WECC's claims in response to Snohomish and the Joint Commenters,[52] the Answering Parties maintain that NERC and WECC never explain how WECC's Reliability Assessment and Performance Analysis program and its Situational Awareness activities can be eligible for FPA section 215 funding under the terms of the statute itself. The Answering Parties note that NERC and WECC instead

[50] *Id.* at 10.

[51] *Id.* at 9-11.

[52] The Answering Parties combined their comments in response to NERC's deficiency letter response with their answer to NERC's answer to Snohomish and Joint Commenters. The deficiency letter response is discussed further below.

rely on the Commission's prior approval of FPA section 215 funding for these activities, and the fact that the activities are consistent with NERC's and WECC's written criteria for determining section 215 fundability, and consistent with NERC's Rules of Procedure. The Answering Parties maintain that the only functions that can be delegated to a Regional Entity are as stated in FPA section 215, i.e., proposing Reliability Standards to the ERO and enforcing Reliability Standards. While the Answering Parties concede that NERC is authorized to "conduct periodic assessments of the reliability and adequacy of the [B]ulk-[P]ower [S]ystem," FPA section 215 does not permit NERC to delegate this function to the Regional Entities and, consequently, does not permit statutory funding of such activities by the Regional Entities.

iii. Deficiency Letter and Response

49. The deficiency letter asked NERC to (1) provide the current and 2015 year-end projections of the $3.4 million in penalty monies withheld in 2015 by WECC to offset payments of penalties imposed on WECC's registered entity functions,[53] and (2) explain if the increase in consultant expenses for transmission planning activities proposed for 2016 relates to WECC's past transmission expansion activities, and, if so, explain the nature of WECC's proposed transmission expansion planning activities.

50. In regard to the Commission's request to provide the current and year-end projections of the $3.4 million in penalty monies withheld in 2015 by WECC, NERC explains that the use of the $3.4 million of penalties was shown in WECC's 2015 business plan and budget and WECC's annual actual cost-to-budget true-up reports for the years 2013 and 2014. NERC explains that $1.4 million was recorded in 2013 and $2.0 million was recorded in 2014 as miscellaneous expenses. NERC explains that, in terms of cash payments, $0.4 million was paid in January 2015 and $1 million in May 2015. NERC states that WECC will pay $1 million in May 2016 and $1 million in 2017.[54] NERC notes that one-half of the payments in May of 2015, 2016, and 2017 have gone or will go to NERC, and the other half to the U.S. Treasury in accordance with the terms of the settlement agreement among the Commission's Office of Enforcement, NERC, WECC, and Peak Reliability relating to the September 8, 2011 outage event, approved by the Commission on May 26, 2015.[55] Accordingly, NERC explains, the

[53] NERC 2015 Budget Filing, Transmittal Letter at 104-105, Attachment 10 at 53, North American Electric Reliability Corp., Docket No. RR14-6-000 (Aug. 22, 2014).

[54] NERC Response at 18.

[55] *Western Electricity Coordinating Council*, 151 FERC ¶ 61,175 (2015).

balance of the $3.4 million in penalty revenues remaining to be paid as of December 31, 2015 is $2.0 million.[56]

51. In regard to the Commission's request to explain if the increase in consultant expenses for transmission planning activities proposed for 2016 relates to WECC's past transmission expansion activities, and to explain the nature of WECC's proposed transmission expansion planning activities, NERC and WECC provide further background as to the nature of the TEPPC's activities. NERC explains that WECC's TEPPC has three main functions: "(1) to oversee and maintain public data bases to support transmission planning across the Western Interconnection; (2) to develop, implement and coordinate planning processes and policy; and (3) to conduct Interconnection-wide transmission planning studies with an eye towards resource and transmission adequacy assessments."[57] NERC explains that "WECC's proposed 2016 transmission planning support activities, and the associated increase in consultant expenses referred to in the Commission's deficiency letter, are directly related to WECC's past transmission planning support activities," and that the scope of WECC's transmission planning related activities has not significantly changed since 2007.[58]

52. NERC explains that WECC experienced a decrease in consultants and contracts expense from the 2014 budget to the 2015 budget due to the expiration of the Regional Transmission Expansion Planning (RTEP) grant from the U.S. Department of Energy (DOE). NERC states that while WECC was able to use the RTEP grant funds efficiently to add significant value to its transmission expansion planning-related activities, "many of the activities funded through the RTEP grant were one-time initiatives to develop or procure tools."[59] NERC states that WECC's budgets for consultants and contracts for 2015 and 2016 (and projected for subsequent years) include, among other things, activities to build upon, enhance, or maintain initiatives that began under the funding provided by the DOE RTEP grant.[60]

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[56] NERC Response at 19.

[57] *Id.* at 19-20.

[58] *Id.* at 20.

[59] *Id.*

[60] *Id.*

iv. Deficiency Letter Comments

53. In their comments on NERC's response to the deficiency letter, the Answering Parties argue that NERC's description of WECC's transmission planning and related activities serves to illustrate the overly broad nature of NERC's and WECC's understanding of what activities may be properly delegated to WECC. The Answering Parties specifically point to the description of WECC's transmission expansion planning activities, as contained in NERC's response, as illustrating the type of activities that are not within the scope of delegable FPA section 215 functions or FPA section 215 funding.

Commission Determination

54. First, we are satisfied with NERC's response regarding the status of the $3.4 million in penalty monies withheld by WECC, and will not require NERC or WECC to file any additional information as to its 2016 business plan and budget on that item. However, with respect to WECC's 2017 business plan and budget, we direct WECC to include information on any further payments made and to be made for penalties imposed on WECC.

55. As a general matter, we find that WECC's Reliability Assessment and Performance Analysis and SAIS activities are within the ambit of those that the Commission has historically recognized as appropriate for statutory funding under FPA section 215, and that we have not previously found reason to distinguish between the kinds of activities that can be funded by FPA section 215 when conducted by NERC versus those conducted by a Regional Entity:

> NERC's proposed activities are the same that we find to be within the ambit of FPA section 215 and thus entitled to receive funding pursuant to section 215 of the FPA for the ERO and should be statutory in the context of the Regional Entities. We see no reason why they would differ on a regional basis.[61]

56. Pursuant to section 215(g) of the FPA, NERC has the statutory authority–indeed obligation–to perform periodic reliability assessments.[62] NERC, in fact, relies on the

[61] 2007 Budget Order, 117 FERC ¶ 61,091 at P 38.

[62] *See* FPA section 215(g) ("The ERO shall conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America.").

eight Regional Entities to provide the region-specific information and analysis contained in ERO periodic assessments. The Commission has authorized the Regional Entities to obtain and analyze such information to support periodic system assessments, "as set out in the Rules of . . . each applicable Regional Entity."[63] NERC and WECC have provided a detailed discussion of how the WECC TEPPC, Market Interface Committee and other Reliability Assessment and Performance Analysis activities support the statutorily-required periodic reliability assessments.[64] The Regional Entities need a guaranteed, consistent source of funds to assist the ERO in performing this statutory requirement.

57. Moreover, based on the additional information and representations made by NERC and WECC regarding WECC's transmission expansion planning and other activities, we find that the primary purpose of the specific activities discussed by the commenters is related to WECC's delegated statutory functions and, therefore, these activities are eligible for funding pursuant to FPA section 215 funding. For example, NERC and WECC explain that the Market Interface Committee focuses on the interface of reliability and market operations, including the consideration of matters pertaining to the impact of WECC's Reliability Standards.[65] Likewise, the planning activities at issue may reveal new problems or conditions, or add to knowledge about existing problems or conditions, that would be considered in the course of identifying, drafting, and voting on amendments to existing WECC Regional Reliability Standards, new WECC Regional Reliability Standards, or continent-wide Reliability Standards. As such, we find these activities are appropriately funded under FPA section 215 and would also fall within the ERO's specific authority in FPA section 215(e)(4) to delegate to Regional Entities authority to propose Reliability Standards.[66] The planning activities may also reveal or

[63] *See* 18 C.F.R. § 39.2(d) (requiring that each user, owner or operator the Bulk-Power System "shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of the Electric Reliability Organization and each applicable Regional Entity").

[64] *See* NERC and WECC Answer at 7-11.

[65] *Id.* at 10 (citing WECC Bylaws, Section 8.2.5). NERC and WECC explain that the Market Interface Committee "leaves the coordination of those [non-reliability related] activities to market participants and the North American Energy Standards Board (NAESB)."

[66] Several commenters in the proceeding addressing NERC's petition for approval of revised Delegation Agreements between NERC and each Regional Entity raise similar

(continued...)

provide further information about system conditions or other facts that would affect how WECC or other Regional Entities decide to assess compliance with, or enforce, existing or future WECC Regional Reliability Standards or continent-wide Reliability Standards. The planning activities, therefore, are appropriately funded under FPA section 215 and also would fall within the ERO's authority under section 215(e)(4) to delegate authority to Regional Entities to enforce Reliability Standards.[67]

58. While we acknowledge that certain WECC activities, including its transmission expansion planning activities and studies, may have other secondary uses, this does not change the fact that the activities are consistent with our approved criteria for determining whether funding is appropriate, and, ultimately, are necessary or appropriate activities for Reliability Standards development and enforcement.[68] We further note that WECC has indicated that its role in maintaining awareness of system conditions is to identify trends and risks to the system, and that it is responsible for all situational awareness activities other than those performed by Peak Reliability as part of its reliability coordinator function. As such, we disagree with Joint Commenters that WECC's situational awareness is duplicative of the responsibilities of Peak Reliability as reliability coordinator and note that the Commission has previously ruled that it is appropriate for a Regional Entity to maintain situational awareness, separate from that of

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issues regarding whether specific tasks are eligible for funding under FPA section 215. In an order issuing concurrently with the order in this proceeding, the Commission states that it defers review of section 215 funding for specific tasks to the annual NERC business plan and budget. *North American Electric Reliability Corp.*, 152 FERC ¶ 61,135, at P 38 (2015).

[67] The Commission has recognized that enforcement of Reliability Standards includes proactive compliance efforts, and has found such activities, carried out by the ERO and Regional Entities, to be eligible for statutory funding. *See* 2007 Budget Order, 117 FERC ¶ 61,091 at PP 28-29 (finding ERO and Regional Entity reliability readiness activities to be acceptable for section 215 funding as "an important facet of . . . proactive efforts to maintain a reliable [B]ulk-[P]ower [S]ystem.").

[68] Statutory Criteria Order, 143 FERC ¶ 61,052 at PP 32, 34, Attachment at 25, 26 (directing NERC in Criteria I.C and II.E to evaluate whether "the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information reasonably necessary to monitor and enforce compliance with Reliability Standards").

the reliability coordinator as necessary for it to comply with applicable Reliability Standards.[69] In making this determination, we also rely on WECC's assertion that it does not and will not undertake any obligations regarding transmission planning under Order No. 1000. However, the Commission will carefully review the scope of all future activities in which WECC may engage to ensure that funds collected pursuant to FPA section 215 are spent only on activities authorized by FPA section 215. To the extent any future WECC activity goes beyond activities that the Commission specifically has found to be eligible for funding pursuant to FPA section 215, WECC should seek alternative funding for those activities or, if it wishes to seek section 215 funding, specifically request and justify such funding for the activity in a future budget proceeding for Commission consideration.

4. WIRAB Budget

59. WIRAB proposes statutory expenses of $1,370,274 in 2016, which is a $356,693 increase from its 2015 budget. To fund its operations in 2016, WIRAB proposes a statutory assessment of $1,239,998, of which $1,048,819 would be allocable to end users in the United States.

60. WIRAB notes that its key activities in 2016 include: (1) rectifying the shortcomings in grid reliability practices at registered entities in the West; (2) improving WECC's ability to identify, analyze, and recommend actions to address major reliability challenges and participate in the analysis of those challenges; (3) creating a high performance organization at Peak Reliability; (4) encouraging WECC and Peak Reliability to adopt more open and transparent data sharing practices; (5) securing adequate and reliable funding for Peak Reliability; and (6) ensuring that both Peak Reliability and WECC can effectively identify and disseminate best practices to maintain physical and cyber security of the Western Interconnection. WIRAB's budget includes 5.5 FTEs for 2016, which is an increase of 1.5 FTEs over 2015.

5. Deficiency Letter and Response

61. The deficiency letter asked NERC to provide additional descriptions for WIRAB's proposed 2016 activities to justify its overall budget and FTE increase from the 2015 budget. In its response to the deficiency letter, NERC noted that in light of WIRAB's statutory status, NERC is not in a position to review and approve or reject the business plans and budgets that WIRAB submits to NERC for submission to the Commission.[70]

[69] 2007 Budget Order, 117 FERC ¶ 61,091 at P 53.

[70] NERC Response at 13-14.

However, at NERC's request, WIRAB provided additional details and descriptions of its planned 2016 activities and explanation of the increase in its budgeted 2016 expenses and FTEs over its 2015 budget.

62. WIRAB states that its goals, initiatives, and activities are similar in 2015 and 2016, and that the major driver of the proposed increase in budget and FTEs is a change in its ability to leverage work previously funded with federal stimulus money to achieve its reliability mission and goals.[71] WIRAB notes that staff members who previously directed the State Provincial Steering Committee reliability-related work are transitioning to WIRAB activities.[72]

63. WIRAB states that it will seek to bolster WECC staff's analytical capabilities to investigate emerging reliability challenges in the West and to encourage WECC to develop improved production cost and power flow analyses of different future resource mixes to identify potential reliability issues such as insufficient ramping capability, insufficient frequency response, or insufficient voltage stability. WIRAB states that in 2015 the State Provincial Steering Committee funded work by GE Energy Consulting to develop a roadmap for assessing the reliability challenges associated with high levels of variable energy resources and the retirement of coal plants in the Western Interconnection. The resulting State Provincial Steering Committee report discussed the types of analysis and data needed to identify and quantify potential reliability problems, as well as the identification and analysis of mitigation options that can provide promising solutions. In 2016, WIRAB states its staff will continue to work with WECC to implement the recommendations and follow the roadmap put forward in the State Provincial Steering Committee report.[73]

64. WIRAB states that it will seek to "encourage WECC to use analytic capabilities to investigate the ramping capability and flexibility of the Western Interconnection in futures with high levels of variable generation."[74] WIRAB states that in 2015, the State

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[71] WIRAB notes that over that past five years, it has benefited from the reliability-related work funded by the State Provincial Steering Committee, which received funds under the American Recovery and Reinvestment Act. This funding ended in May 2015. *Id.* at 14.

[72] *Id.*

[73] *Id.*

[74] *Id.* at 15.

Provincial Steering Committee funded work by Energy and Environmental Economics (E3) to develop and demonstrate a new tool for assessing the ramping capability and system flexibility of the Western Interconnection. WIRAB states that this was a collaborative project among the State Provincial Steering Committee, WECC, the National Renewable Energy Laboratory, and E3, and that the report investigated the need for power system flexibility to ensure reliable and economic operations of the interconnected Western electricity system under higher penetrations of variable energy resources. In 2016, WIRAB proposes that its staff will "continue to work with WECC, E3, and the National Renewable Energy Laboratory to further develop a flexibility planning paradigm and to use the Renewable Energy Flexibility (REFLEX) model to assess system flexibility needs in futures with high levels of variable generation."[75]

65. WIRAB states that it will seek to encourage WECC to evaluate the impacts large-scale development of non-synchronous generation may have on system frequency response and transient stability, and to examine the impact that large-scale tripping of photovoltaics, due to outdated interconnection standards, may have on grid reliability. WIRAB states that in 2015, GE Energy Consulting provided the State Provincial Steering Committee with an analytical framework and a roadmap for assessing frequency response, transient stability and weak grid issues associated with the large-scale development of non-synchronous generation. The State Provincial Steering Committee also funded work by EQL Energy to examine the technical challenges, operational issues, and steps that utilities and regulators can take to prepare for increased levels of distributed energy resources. The resulting report identified the large-scale tripping of distributed energy resources as a potential reliability issue for the Western Interconnection, and found that at higher penetrations of distributed energy resource systems this automatic shut-off can have undesirable impacts on grid reliability. In 2016, WIRAB staff will continue to work with WECC to implement an analytical framework to conduct round-trip production cost and power flow modeling to analyze system frequency response, transient stability, and weak grid issues.[76]

66. WIRAB states that it will encourage WECC to use its analytic capabilities to investigate the reliability implications of the U.S. Environmental Protection Agency's Clean Power Plan.[77] WIRAB states that in 2015, the State Provincial Steering

[75] *Id.* at 15.

[76] *Id.*

[77] The Clean Power Plan was issued by the EPA as a Final Rule on August 3, 2015. *See Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Docket No. EPA-HG-OAR-2013-0602 (Aug. 3, 2015),

(continued...)

Committee funded work by Energy Solutions to develop future state-level resource mixes that could result from strategies that states may employ to comply with the Clean Power Plan. The resulting report documented the assumptions underlying four planning scenarios developed in consultation with a State Provincial Steering Committee modeling work group. WIRAB submitted two of the scenarios to WECC as a "practice run" of the modeling and analysis needed to analyze the Clean Power Plan prior to the release of the final rule for the plan. In 2016, WIRAB staff will continue to work with WECC to analyze the reliability implications of the Clean Power Plan, and WIRAB will work with western states to develop future state-level resource mixes that could be used to comply with the Clean Power Plan.[78]

67. WIRAB states that it will foster the testing of a methodology to establish dynamic transfer limits on major transmission paths in the Western Interconnection. WIRAB has encouraged both WECC and Peak Reliability to examine the current method of assigning static transfer limits to major transmission paths based on long-term operating limits. WIRAB states that in 2015, the State Provincial Steering Committee funded work by Quanta Technology to develop a new methodology. The resulting report provided a detailed description of a new Flexible, Adaptable, and Scalable Path Transfer Capability (FASTC) methodology. The report included a detailed description of the analytical methodology and how to implement it in different calculation periods, including real-time. In 2016, WIRAB proposes that its staff will continue to work with WECC and (as necessary) Peak Reliability to explore opportunities to further develop this methodology and an implementation tool for system operators. WIRAB states that its staff will work closely with WECC's Path Operator Implementation Task Force to align the work on the FASTC methodology with the Path Operator Implementation Task Force's efforts to develop a new paradigm for setting path limits.[79]

68. WIRAB states that it will examine the impact of new market structures on grid reliability, and seek to encourage WECC to evaluate the major changes to regional power flows that may result from higher penetration levels of renewable energy. The development of the California Independent System Operator's (CAISO) expanding Energy Imbalance Market (EIM) and the potential development of a regional independent system operator (ISO) in the West represent efforts to expand the market footprint and

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80 Fed. Reg. 64,662 (Oct. 23, 2015) (to be codified at 40 C.F.R. pt. 60) (Clean Power Plan).

[78] NERC Response at 16.

[79] *Id.*

use transmission to balance over-generation from renewable resources. WIRAB states that in 2015, the State Provincial Steering Committee funded work by E3 to describe the anticipated changes in resource mix and transmission path flows across the western United States over the next decade. One conclusion of this work, according to WIRAB, is that major changes to regional power flows may begin to occur at higher penetration levels of renewables, and higher reliance on solar power would exacerbate the trend. The development of the EIM and the potential development of a regional ISO in the West may produce real-time reliability benefits in a future with high penetrations of renewable resources, according to WIRAB. In 2016, WIRAB staff will work to encourage WECC to evaluate the potential for major changes to Western regional power flows and the potential reliability benefits of a Western EIM or a regional ISO. WIRAB states that its staff will work closely with the EIM Body of State Regulators, the CAISO, and WECC to ensure that reliability benefits of the EIM are more fully understood.[80]

Commission Determination

69. The information NERC and WIRAB provided in response to the Commission's deficiency letter aided in our review of WIRAB's proposed 2016 business plan and budget. Based on the information provided in this proceeding, the Commission accepts the WIRAB 2016 budget. However, the Commission is mindful of WIRAB's expanded activities over the last two years and its increased budget. Therefore, the Commission will carefully review the scope of future activities in which WIRAB may engage to ensure that funds collected pursuant to FPA section 215 are spent only on activities authorized by FPA section 215. To the extent any future WIRAB activity goes beyond activities that are eligible for funding pursuant to FPA section 215, WIRAB should seek alternative funding for those activities.

The Commission orders:

(A) NERC's 2016 business plan and budget is hereby accepted.

(B) The Regional Entity 2016 business plans and budgets are hereby accepted.

(C) The WIRAB 2016 budget is hereby accepted for funding.

[80] *Id.* at 16-17.

(D) WECC is directed to include additional information in its 2017 business plan and budget, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

153 FERC ¶ 61,130
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

North American Electric Reliability Corporation — Docket Nos. RR15-2-001
RR15-2-002

ORDER CONDITIONALLY ACCEPTING COMPLIANCE FILINGS

(Issued November 4, 2015)

1. On May 20, 2015 and July 6, 2015, North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted compliance filings in accordance with the Commission's February 19, 2015 order conditionally accepting NERC's risk-based compliance monitoring and enforcement program (CMEP), also known as the Reliability Assurance Initiative (RAI).[1] As discussed below, we accept NERC's compliance filings subject to NERC making an additional compliance filing to modify its Rules of Procedure within 120 days of the date of this order, and providing additional information in its annual report on RAI.

I. Background

2. In the February 19 Order, the Commission approved NERC's implementation of RAI, which represents a transition to a risk-based approach to compliance monitoring and enforcement. The February 19 Order was based on a finding that focusing compliance resources on higher-risk issues that matter more to reliability is reasonable. In approving the implementation of RAI, however, the Commission directed NERC to submit a compliance filing proposing revisions to the NERC Rules of Procedure that articulate the RAI concepts and programs, as well as providing details on NERC's planned oversight of and evaluation of the RAI program.

3. With regard to the directed revisions to the Rules of Procedure, the Commission stated that NERC's proposal should, at a minimum, "recognize the existence of the RAI

[1] *North American Electric Reliability Corp.*, 150 FERC ¶ 61,108 (2015) (February 19 Order).

process, articulate basic RAI concepts and define fundamental RAI elements," as well as provide for Commission approval of "significant" changes in RAI as NERC develops and implements its risk-based approach to compliance monitoring and enforcement.[2] The Commission stated, however, that it does "not expect NERC to include in the Rules of Procedure detailed procedures that would unduly hamstring the intended flexibility and streamlined processes that are the hallmark of RAI."[3] While providing NERC flexibility in the implementation of RAI, the Commission concluded that revisions to the Rules of Procedure are necessary to maintain meaningful Commission oversight and ensure that the ERO rules provide fair and impartial procedures for enforcement.

4. The Commission also directed NERC to include in this compliance filing "details on: a) its oversight processes for the RAI program and b) how it intends to measure the success of the risk-based approach to compliance monitoring and enforcement," including the types of data-driven metrics that will be used to track the RAI program as it develops.[4] In addition, the Commission imposed certain conditions on the implementation of RAI. Specifically, the Commission directed NERC to (1) make information regarding both Critical Infrastructure Protection (CIP) Reliability Standard and non-CIP compliance exceptions available to the public as currently provided for under the Find, Fix, Track and Report (FFT) program;[5] (2) require "some level of formal review" of an entity's internal controls before granting the entity the flexibility to self-log instances of noncompliance, including "an appropriate level of standardization for the content and review of an entity's compliance logs;"[6] and (3) while generally not including compliance exceptions in a registered entity's compliance history for penalty purposes, assess subsequent noncompliance of the same or closely-related Reliability Standards and requirements to determine a registered entity's qualification for compliance exception treatment.[7] The Commission also clarified that a compliance exception will be considered closed 60 days after being reported to the Commission,

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[2] *Id.* P 30.

[3] *Id.*

[4] *Id.* P 32.

[5] *Id.* P 39.

[6] *Id.* PP 42-43.

[7] *Id.* PP 44-45.

unless it is determined that a compliance exception was obtained based on a material misrepresentation.[8]

5. In addition, the Commission accepted NERC's proposal to submit an annual informational filing on RAI, finding that "the annual report content suggested by NERC [is] reasonable."[9] Specifically, the Commission directed NERC to submit an annual report as proposed by NERC, to include observed trends by standard, region or other categories, as well as examples of matters that were treated as compliance exceptions.[10] In addition, the Commission directed NERC to include certain additional information in the annual report, including the interplay between the RAI program and other NERC program areas, such as a feedback loop from RAI to the standards development process and the analysis of Bulk-Power System events. The Commission also directed NERC to address whether a baseline audit is necessary to properly evaluate a registered entity's internal controls. Finally, the Commission directed NERC to provide "an update on NERC's oversight of the RAI program (e.g., whether RAI has been implemented in a consistent manner across the Regional Entities)," an update on "the metrics that NERC has or will employ to measure the effectiveness of the RAI program," and examples of "how a Regional Entity assesses and factors into a registered entity's risk assessment and audit scope that entity's use of NERC Alerts, Lessons Learned, Reliability Guidelines, and other NERC learning tools."[11]

II. NERC's Compliance Filings

A. May 20, 2015 Compliance Filing

6. On May 20, 2015, NERC submitted a compliance filing providing additional detail on its oversight processes, measures of success, a methodology for assessing an entity's internal controls and the circumstances under which an alternate methodology will be used, and standardization of the content and review of an entity's compliance logs as required in the February 19 Order. With respect to oversight processes, NERC discusses four aspects: (1) risk-based CMEP oversight; (2) compliance assurance

[8] *Id.* PP 47-48.

[9] *Id.* P 49.

[10] *Id.* (citing NERC's November 3, 2014 Informational Filing on the Reliability Assurance Initiative in Docket No. RR15-14-000 at 51).

[11] *Id.* PP 49-52.

oversight; (3) compliance enforcement oversight; and (4) continued training of ERO Enterprise (i.e., NERC and the Regional Entities) staff.

7. NERC's filing also proposes success factors and some related metrics to assess the success of the implementation of the risk-based CMEP. Specifically, NERC states that it will measure the following success factors: (1) ERO Enterprise staff competency; (2) information and outreach; (3) consistency; (4) regulator trust; (5) balanced transparency; (6) metrics identified; and (7) recognized value.

8. NERC also provides a methodology for the review of a registered entity's internal controls to determine the entity's eligibility for the self-logging program. Specifically, Attachment A to NERC's May 20, 2015 compliance filing describes the self-logging program and the methodology that Regional Entities use to review internal controls associated with a registered entity's ability to self-assess and mitigate possible violations that, as currently required by the risk-based CMEP, pose only a minimal risk to Bulk-Power System reliability. Attachment A establishes the formal review of an entity's internal controls that must be undertaken by the Regional Entities prior to granting the ability to self-log, as required by the February 19 Order. NERC also clarifies that the formal review of a registered entity's eligibility for self-logging is separate and apart from an internal controls evaluation (ICE).[12] NERC states that this formal review should be available any time a registered entity seeks admission to the self-logging program and would likely take place outside of a formal compliance monitoring engagement. Nevertheless, NERC states that a self-logging evaluation may be performed at the same time in the context of an ICE, provided that the Regional Entity performs the review in accordance with the requirements in Attachment A.[13]

9. In addition, NERC provides an explanation of the anticipated content and review process associated with a registered entity's log of instances of noncompliance. Specifically, NERC explains that a log should "not provide any less information than what is contained in a typical Self-Report and corresponding Mitigation Plan," including a description of the facts surrounding the noncompliance and its discovery, a risk assessment, and a description of mitigating activities. NERC explains further that a Regional Entity must review each noncompliance included in a registered entity's log, to determine whether (1) the logged noncompliance is sufficiently described; (2) the minimal risk assessment is justified and reasonable; and (3) the mitigation activities for the noncompliance are appropriate and adequate. In addition, NERC explains that where a Regional Entity determines that any logged instances of noncompliance "are

[12] May 20, 2015 Compliance Filing at 14-15.

[13] *Id.*

insufficient due to unclear or missing information, unsupported minimal risk determinations, or inadequate mitigations (e.g., recurring instances of noncompliance stemming from the same or substantially similar root cause)," the Regional Entity may (1) work with the entity to correct unsatisfactory log entries; (2) process the instance of noncompliance through an alternate disposition method; or (3) modify or revoke self-logging privileges.[14]

B. July 6 2015 Compliance Filing

10. On July 6, 2015, NERC submitted a compliance filing proposing revisions to section 400 and Appendices 2 and 4C of the NERC Rules of Procedure. NERC explains that the proposed revisions recognize the risk-based CMEP processes and concepts, as directed by the Commission. Specifically, NERC proposes definitions for key RAI-related terms: compliance exceptions; internal controls evaluation; and self-logging. In addition, NERC proposes revisions to the Rules of Procedure to (1) highlight the types of data NERC uses to identify annual risk elements; (2) explain that the type and frequency of the compliance monitoring tools appropriate for a particular entity is based on that entity's specific reliability risk; and (3) include the principles related to the exercise of enforcement discretion.

11. NERC explains that the proposed revisions to section 400 of the Rules of Procedure are intended to articulate the process by which NERC will identify continent-wide reliability risks, which will represent the focus for monitoring for the next year as inputs to the Regional Entities' individual registered entity oversight plans. In addition, NERC proposes revised requirements for Regional Entities, to include in their Regional Entity CMEP implementation plan, details on the regional risk assessment process and results, the Reliability Standards and requirements identified by regional risk assessments, and the Regional Entity annual audit plan. NERC explains that the proposed revisions are intended to "help promote consistency and compliance with NERC's uniform [CMEP]."[15] NERC states that its proposed revisions to Appendices 2 and 4C are intended to define the fundamental RAI concepts and processes.

III. Notice and Responsive Pleadings

12. Notice of NERC's May 20, 2015 compliance filing was published in the *Federal Register*, with comments or protests due on or before June 10, 2015.[16] Notice of NERC's

[14] *Id.* at 16-18.

[15] July 6, 2015 Compliance Filing at 7.

[16] 80 Fed. Reg. 31,902 (June 4, 2015).

July 6, 2015 compliance filing was published in the *Federal Register*, with comments or protests due on or before July 27, 2015.[17] None was filed.

IV. Discussion

13. As described further below, we conditionally accept NERC's compliance filings, subject to NERC making an additional compliance filing to modify its Rules of Procedure within 120 days of the date of this order and providing additional information in its annual report on RAI.

A. Additional Information Regarding RAI Oversight

14. In the February 19 Order, the Commission found that NERC's plan for oversight of the RAI programs was lacking in specifics beyond the first quarter of 2015. While the Commission found that NERC's commitment to review Regional Entity implementation of RAI during the first quarter of 2015 was appropriate to ensure that the program is implemented appropriately at its outset, the Commission directed NERC to provide details on its plan for ongoing oversight. Specifically, the Commission directed NERC to provide details on, among other things, its oversight processes for the RAI program.[18]

NERC's Compliance Filing

15. In its May 20, 2015 compliance filing, NERC explains that the oversight approach for the risk-based CMEP implementation includes (1) reviewing processes and procedure documentation to assess consistency with risk-based CMEP design; (2) sampling the activities related to performance of specific components of the risk-based CMEP design for quality assurance; and (3) providing feedback, training, and recommendations to Regional Entities for improvement.[19]

16. NERC states that it is conducting compliance assurance oversight activities through a two-phased approach. In the first phase, which has been completed, NERC visited all eight Regional Entities to review their risk-based process documentation, including procedures associated with the Inherent Risk Assessment (IRA) and ICE.[20]

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[17] 80 Fed. Reg. 40,055 (July 13, 2015).

[18] February 19 Order, 150 FERC ¶ 61,108 at P 32.

[19] May 20, 2015 Compliance Filing at 4.

[20] NERC states that this documentation includes supporting regional process documents such as policies, procedures, narratives, and flowcharts describing the

(continued ...)

NERC states that it compared the Regional Entities' basic concepts to the ERO Enterprise's guidance documents and procedures associated with these programs. NERC also states that it provided feedback identifying differences or opportunities for improvement and increased consistency in regional processes. In addition, NERC explains that it held regular and periodic discussions with the Regional Entities to follow up on the results of the site visits. NERC states that it plans to continue feedback discussions as procedures are revised.[21]

17. NERC explains that under phase two it will evaluate "how risk-based compliance monitoring concepts are used, the determinations made when using these concepts, and the results of their practical application by the Regional Entities."[22] NERC states that phase two will continue throughout the remainder of 2015 and into 2016 and will "focus on samples of compliance monitoring work by each Regional Entity."[23]

18. With regard to compliance enforcement, NERC states that its oversight includes three main categories of activities: (1) tracking data flow and calculating metrics; (2) performing an annual review and evaluation; and (3) developing feedback, guidance, and training.[24] NERC explains that it develops "performance indices on a regular basis to track and report the performance of the Regional Entities and NERC in processing violations and mitigation." NERC explains that for 2015, the "evaluations are focusing on the new processes under the risk-based CMEP including triage, self-logging, and Compliance Exceptions." NERC states that its enforcement staff provides feedback, guidance, and training to the Regional Entities and will provide additional training in 2015 to Regional Entity staff and industry stakeholders on areas such as compliance exceptions and the self-logging program. NERC explains that it will develop this training based on early experience with implementing the programs, as well as observations from the various reviews and evaluations. NERC states that it also computes performance

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Regional Entity's execution and application of the design for the risk-based CMEP applicable to the ERO Enterprise.

[21] May 20, 2015 Compliance Filing at 4-5.

[22] *Id.* at 5.

[23] *Id.*

[24] *Id.* at 6.

indices on a regular basis to track and report the performance of the Regional Entities and NERC in processing violations and mitigation.[25]

19. NERC states that it prioritized training for ERO Enterprise staff to provide oversight and transparency for the risk-based CMEP. During 2015, according to NERC, its staff, supported by Regional Entities, will continue to develop and provide comprehensive and ongoing education and training on the transformation of compliance monitoring and enforcement for ERO Enterprise staff. As part of phase one, NERC explains, the training focused heavily on consistent implementation of the IRA and ICE components; phase two will incorporate lessons learned and other examples obtained through actual application of IRA and ICE.[26]

Commission Determination

20. While NERC provided additional information on its oversight of the RAI program, as directed in the February 19 Order, we believe that the Commission's monitoring would benefit from additional information regarding NERC's oversight plan going forward. We recognize, however, that the Commission directed NERC to "address and provide an update on NERC's oversight of the RAI program" in its upcoming annual report.[27] Therefore, we accept this aspect of NERC's May 20, 2015 compliance filing on the condition that NERC provide in its annual reports on RAI the following additional types of information.

21. As an initial matter, NERC provided a description of the phase 1 assessment and the activities completed as of the time it submitted its compliance filings. We direct NERC to provide the results of that assessment, as well as future assessments, in its annual reports. NERC should provide its assessment of the Regional Entities' consistency in the implementation of risk-based CMEP, including a description of any inconsistencies found in Regional Entities' risk-based process documentation and application, and how such inconsistencies were or will be resolved. Such information is important with respect to how each Regional Entity has implemented and will implement the RAI program; therefore, we direct NERC to include this information in its annual reports on RAI.

[25] *Id.* at 6-7.

[26] *Id.* at 7.

[27] February 19 Order, 150 FERC ¶ 61,108 at P 52.

22. It would also be informative for NERC to provide in its annual reports an analysis of self-logging data provided by each Regional Entity to measure the quality and consistency of self-logging across regions. This analysis should include information quantifying the number of applicants and successful applicants to receive self-logging authority, and information on the quality and disposition of self-logs, including whether they included all elements required by NERC's self-logging program.[28] Such information will assist the Commission with its ongoing oversight of the RAI program.

B. Measures of Success and Associated Metrics

23. As noted above, the Commission found in the February 19 Order that NERC's plan for oversight of the RAI programs was lacking in specifics beyond the first quarter of 2015. Specifically, the Commission directed NERC to provide details on "how it intends to measure the success of the risk-based approach to compliance monitoring and enforcement, to include the types of data-driven metrics it will track as the RAI program develops."[29]

NERC's Compliance Filing

24. NERC states that it has developed success factors and related metrics to assess the success of the implementation of the risk-based CMEP. NERC further states that over the course of 2015, it "will collect information related to each measurement in order to determine appropriate benchmarks and possible targets for future years." NERC also states that "each metric may support more than one success factor." NERC proposes seven success factors: (1) ERO Enterprise staff competency; (2) information and outreach; (3) consistency; (4) regulator trust; (5) balanced transparency; (6) metrics identified; and (7) recognized value.[30]

25. NERC defines the ERO Enterprise staff competency success factor as having ERO staff that performs key activities being trained and competent in their areas of responsibility and regarded as being well qualified in their roles by registered entities. NERC further states that it measured achievement of this objective through several methods including the percentage of staff receiving training and the review of exit results from audit engagement surveys.

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[28] May 20 Filing, Attachment A at 5.

[29] February 19 Order, 150 FERC ¶ 61,108 at P 32.

[30] May 20, 2015 Compliance Filing at 10-13.

26. NERC defines its information and outreach success factor as registered entities having the information they need to prepare for engaging with Regional Entities and NERC in risk-based compliance and enforcement activities. NERC states that it now partly meets this objective through webinars, workshops, and newsletters and that it will continue to provide support for various industry and trade events.

27. NERC defines the consistency success factor as having tools, processes, and templates used by the Regional Entities for risk-based compliance and enforcement that are consistent where consistency is important, with NERC having adequate oversight of the relationship between Regional Entities and registered entities.[31] NERC states that it ensures consistency through oversight and registered entities may also report consistency-related concerns through NERC's Regional Consistency Reporting Tool.

28. NERC defines the regulator trust success factor as the ERO Enterprise having strengthened the trust of the Commission and applicable Canadian authorities in risk-based compliance and enforcement. NERC states that it continues to coordinate and collaborate with the Commission and other Applicable Governmental Authorities to ensure proper implementation of risk-based processes and that those authorities have access to the information necessary to discharge their oversight responsibilities.

29. NERC defines the balanced transparency success factor as the ERO Enterprise having determined an appropriate level of transparency for various facets of risk-based compliance and enforcement, balancing the efficiency and the confidentiality needs of a registered entity with the needs of the industry to learn from others.[32] NERC notes that it has implemented an elevated level of transparency by posting compliance exceptions and regular public reports on a variety of implementation matters.

30. NERC defines the metrics identified success factor as metrics having been identified for key expected results from risk-based compliance and enforcement and benchmarked for 2015. NERC states that it has reported on the results of a number of metrics that reflect the growth and expansion of the risk-based compliance monitoring and enforcement processes. NERC further states that during 2015 the ERO Enterprise will continue to develop any additional necessary metrics that correlate the implementation of the risk-based processes with the reliability of the Bulk-Power System.

31. NERC defines the recognized value success factor as the value of risk-based compliance and enforcement being of demonstrable value to the consuming public and

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[31] May 20, 2015 Compliance Filing at 11-12.

[32] *Id.* at 12.

clearly and publicly articulated.[33] NERC states that it will "measure this value through benchmarking of the effectiveness survey results for future comparison."

Commission Determination

32. While NERC's compliance filing contains a description of how it intends to measure success (i.e., its proposed success factors), NERC's filing does not specifically include the "types of data driven metrics it will track as the RAI program develops." Specifically, none of the proposed success factors have clearly defined metrics to allow the evaluation of the program over time. Accordingly, we conditionally accept this part of NERC's May 20, 2015 compliance filing, subject to NERC providing additional information in its annual report.

33. We direct NERC to develop success factors and metrics, in lieu of or in addition to those proposed in the May 20, 2015 compliance filing, that will enable NERC and the Commission to evaluate the success of the RAI program, perform a thorough analysis of lessons learned through experience with the RAI program, and identify any needed improvements. For example, as part of this proceeding, NERC noted that the streamlined processes that are the hallmark of RAI would allow fewer resources to be focused on minor violations.[34] Similarly, NERC maintained that RAI reforms will result in improvements to reliability, such as faster detection and remediation times for minor violations.[35] Accordingly, we direct NERC to provide revised success factors and metrics that could illustrate these benefits, as well as any needed improvements, as part of its annual report.[36] To assist NERC in developing revised metrics, we also direct

[33] *Id.* at 13.

[34] *See* November 3, 2014 Informational Filing on the Reliability Assurance Initiative in Docket No. RR15-2-000 at 11.

[35] *See id.* at 12.

[36] Examples of these may include assessing whether the program results in more efficient use of compliance and enforcement resources; improved identification, assessment, and correction of possible violations through greater use of internal controls; or decreases in the time to detect and remediate possible violations through self-logging. They may also include measuring the timeliness of training of ERO and Regional Entity staff on risk-based CMEP components; the number of eligible entities that apply for self-logging; timeliness of action on registered entity requests to self-log; or annual increases in the number of reliability coordinators, balancing authorities, and transmission operators requesting internal control evaluations.

Commission staff to work with NERC staff in developing its revised success factors and metrics.

34. In addition, while we agree that trust and collaboration between the Commission and NERC is critical to the long-term success of the RAI program, we find that NERC's proposed regulator trust factor is not an effective metric for measuring the success of the RAI program, given that the notion of "regulator trust" is a subjective concept that is not conducive to quantitative measurement. Therefore, we direct NERC to discontinue the use of this specific success factor.

C. Registered Entity Document Retention Period

35. In the February 19 Order, the Commission conditioned its approval of NERC's RAI implementation on NERC requiring some level of formal review of an entity's internal controls before granting the flexibility to self-log instances of noncompliance. Further, the Commission required NERC in its compliance filing to provide a methodology for assessing an entity's internal controls and the circumstances under which an alternate methodology will be used in place of an ICE.

36. In the ERO Enterprise Self-Logging Program, Attachment A to the May 20, 2015 compliance filing (Self-Logging Program), NERC addresses data retention requirements for registered entities. With respect to data retention for self-logged items, the proposed program's procedure states the following:

> The registered entity will maintain evidence to support the details included in the description of the noncompliance, the minimal risk assessment of the noncompliance, and the completion of mitigation activities for each instance of noncompliance recorded on the log. The registered entity shall maintain this evidence until the Regional Entity verifies completion of the mitigation activities, subject to the following qualification: If the Regional Entity has not verified the completion of the mitigation activities for 12 months from the later of the date the Regional Entity sent the Notice of Compliance Exception treatment or the date the registered entity completes the mitigation activities, the registered entity is no longer required to maintain the evidence.[37]

37. We find that NERC's proposed 12-month data retention period is insufficient to allow NERC and the Commission to maintain proper oversight of compliance exceptions as required in the February 19 Order. If registered entities are only required to maintain

[37] May 20, 2015 Compliance Filing, Attachment A at 6.

relevant materials for 12 months following a notice of compliance exception treatment, relevant data could be disposed of just prior to or during oversight activities.[38] Accordingly, we condition our acceptance of NERC's May 20, 2015 compliance filing on NERC requiring registered entities to maintain evidence related to compliance exceptions for no less than 18 months from the later of the date the Regional Entity sent the notice of compliance exception treatment or the date the registered entity completes the mitigation activities.

D. Proposed Revisions to NERC's Rules of Procedure

38. In the February 19 Order, the Commission stated that NERC must include the fundamental RAI concepts and elements in the NERC Rules of Procedure. Specifically, the Commission stated that NERC's Rules of Procedure should, at a minimum, "recognize the existence of the RAI process, articulate basic RAI concepts and define fundamental RAI elements," as well as provide for Commission approval of "significant changes in RAI as NERC develops and implements its risk-based approach" to compliance monitoring and enforcement.[39] In addition, the Commission stated that it does "not expect NERC to include in the Rules of Procedure detailed procedures that would unduly hamstring the intended flexibility and streamlined processes that are the hallmark of RAI."[40] While providing NERC flexibility in the implementation of RAI, the Commission concluded that revisions to the Rules of Procedure are necessary to maintain meaningful Commission oversight and ensure that the ERO rules provide fair and impartial procedures for enforcement.

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[38] NERC acknowledged that it intends to include compliance exceptions in its annual FFT review with Commission staff. *See* NERC's September 18, 2015 *Annual Report on the Find, Fix, Track, and Report Program*, Docket No. RC11-6-004, at 15. Thus, for example, NERC staff's evaluation of a sample of compliance exceptions over a twelve-month period likely would take several weeks or months to obtain and review all the data. If registered entities are only required to retain data for 12 months, NERC may not be able to fully investigate compliance exceptions that occurred at the beginning of the sampling period.

[39] February 19 Order, 150 FERC ¶ 61,108 at P 30.

[40] *Id.*

Commission Determination

a. Codifying the Self-Log Review Period

39. In its November 3, 2014 filing proposing RAI, NERC stated that registered entities submit their self-logs for review by the Regional Entity every three months, and noted that the Regional Entity may adjust this period to six months based on its experience with the registered entity.[41] As noted above, in the February 19 Order, the Commission stated that the NERC Rules of Procedure should "at a minimum, recognize the existence of the RAI processes, articulate basic RAI concepts and define fundamental RAI elements, and require Commission approval for significant changes in RAI as NERC further develops and implements its risk-based approach."[42] We find that the Regional Entity review period for self-logged items in the Self-Logging Procedure is a "fundamental RAI element" in streamlining the processes of NERC's risk-based CMEP for minor risk instances of non-compliance. While we find the three-month review period with the possibility of adjustment to six months based on experience to be reasonable, we note that NERC did not codify this review period in its proposed revisions to the Rules of Procedure. Without such codification in the Rules of Procedure, the self-logging review period for Regional Entities could be subject to change without notice to, or approval from, the Commission. Such change to the Self-Logging Procedure would be a significant change in RAI that would warrant Commission review as contemplated in the February 19 Order. Accordingly, we direct NERC to make a compliance filing within 120 days of the date of this order modifying the Rules of Procedure to include the self-logging review period as described in its November 3, 2014 filing.

b. Conforming Changes to the Rules of Procedure

40. While NERC proposed a number of changes to the Rules of Procedure intended to reflect the fundamental RAI concepts and elements, we have identified certain areas where conforming changes or updates to the Rules of Procedure have not been made to reflect the risk-based CMEP. First, NERC did not propose revisions to the data retention requirements for the ERO and Regional Entities in Appendix 4C, section 9.0 to cover data and other information related to self-logging. The current language covers data generated by other discovery methods including, among others, compliance audits, self-certifications, spot checks, compliance investigations, and self-reports. NERC did not

[41] November 3, 2014 Informational Filing on the Reliability Assurance Initiative in Docket No. RR15-2-000 at 58.

[42] February 19 Order, 150 FERC ¶ 61,108 at P 30.

provide an explanation as to why self-logged items and information and data relating to them would not be subject to the existing data retention provisions.

41. Second, NERC did not propose revisions to Appendix 4C, section 5.1 or elsewhere to reflect that NERC currently provides Commission staff with a non-public preliminary notice of self-logged matters received by Regional Entities, similar to the preliminary notice provided to staff for other possible or alleged violations.[43] NERC did not provide an explanation for why this practice should not be reflected in the Rules of Procedure. Third, the Commission, in the February 19 Order, directed NERC to publicly post compliance exceptions.[44] However, NERC did not propose modifications to Rules of Procedure section 400.11, which addresses public posting. Each of these issues reflects a fundamental concept or element of RAI that should be reflected in the Rules of Procedure.

42. Therefore, we direct NERC to propose revisions to the Rules of Procedures to update the appropriate sections or, in the alternative, provide an explanation as to how the RAI components listed above are addressed in the current Rules of Procedure or NERC's proposed amendments to the Rules of Procedure in the compliance filing due within 120 days of the date of this order.

The Commission orders:

(A) The Commission hereby accepts NERC's compliance filings, subject to conditions as discussed in the body of this order.

(B) NERC is hereby directed to submit a compliance filing within 120 days of the date of this order, as discussed in the body of this order.

[43] Section 39.7(b) of the Commission's regulations requires that NERC and the Regional Entities shall "have procedures to report promptly to the Commission any self-reported violation or investigation of a violation or an alleged violation of a Reliability Standard.." *See also* current CMEP section 8.2.

[44] February 19 Order, 150 FERC ¶ 61,108 at P 39.

(C) NERC is hereby directed to include additional information in its future annual reports on the risk-based CMEP, as discussed in the body of this order.

By the Commission. Commissioner LaFleur is concurring with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners:

North American Electric Reliability Corporation — Docket No. RR15-2-001
RR15-2-002

(Issued November 4, 2015)

LaFLEUR, Commissioner, *concurring*:

As the Commission reviews the Reliability Assurance Initiative (RAI), it is essential to strike a balance between ensuring appropriate Commission oversight and providing the North American Electric Reliability Corporation (NERC) and the Regional Entities sufficient flexibility to implement the RAI program to achieve its intended efficiencies and benefits. On the whole, I believe today's order strikes an acceptable balance of those two objectives.

The RAI program grew out of a well-documented concern – discussed for years on the record in reliability technical conferences and Commission dockets – that NERC and the Regional Entities' reliability work was unsustainably bogged down in paperwork on relatively minor issues, which detracted from our collective ability to focus on more significant reliability matters. Going forward, I believe we must be careful not to require, as part of our ongoing oversight, the type of overly prescriptive and time-consuming analysis that the RAI program was designed to avoid, which would "unduly hamstring the intended flexibility and streamlined processes that are the hallmark of RAI."[45] FERC and NERC should focus our attention on significant issues before us like cybersecurity, geomagnetic disturbances, and adapting the electric grid to changes in the resource mix. We should also stay focused on the risk-based prioritization that led us to approve RAI, and not require NERC to repeatedly justify that program.

Accordingly, I respectfully concur.

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Cheryl A. LaFleur
Commissioner

[45] *North American Electric Reliability Corp.*, 150 FERC ¶ 61,108, at P 30 (2015).

153 FERC ¶ 61,024
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RR15-4-001

ORDER ON COMPLIANCE FILING

(Issued October 15, 2015)

1. On July 17, 2015, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a compliance filing in response to the Commission's March 19, 2015, order approving, in part, proposed revisions to NERC's Rules of Procedure that would implement NERC's Risk-Based Registration (RBR) initiative in the above referenced docket.[1] The March 19 Order generally approved the RBR proposal, but denied, without prejudice, NERC's proposal to eliminate the load-serving entity function from the registry process, finding that NERC had not adequately justified its proposal. In doing so, the Commission directed NERC to provide additional information to support this aspect of its proposal to address the Commission's concerns. For the reasons discussed below, we accept NERC's compliance filing to remove the load-serving entity as a functional registration category, and direct NERC to submit an informational filing on the actual effects of this change after it is implemented.

I. Background

2. On December 11, 2014, NERC submitted a petition for approval of proposed revisions to its Rules of Procedure that would implement the RBR initiative. NERC proposed major reforms to the registration process in the Rules of Procedure to include the elimination of the purchasing-selling entity, interchange authority, and load-serving entity functional registration categories. NERC also proposed modifications to the

[1] *North American Electric Reliability Corporation*, 150 FERC ¶ 61,213 (2015) (March 19 Order).

thresholds for registering entities as distribution providers and procedural improvements to the registration process.

3. In the March 19 Order, the Commission approved in part, and denied in part, NERC's RBR petition. The Commission found NERC's overall goal of ensuring entities are registered and made subject to the Reliability Standards based on the risk they pose to reliability reasonable and adequately justified. The Commission found that NERC's alignment of the registration process with the risks to the interconnected transmission network posed by different types of entities is an improvement. Further, the Commission found that NERC and stakeholders will benefit from the proposed revisions as efforts will appropriately be directed towards activities with a greater potential impact on bulk electric system reliability. The Commission agreed with NERC that it is important to achieve reliability risk mitigation while ensuring the reliability and security of the interconnected transmission network, and the RBR initiative is consistent with this pursuit.[2] Thus, the Commission approved most aspects of NERC's proposal with the exception of the removal of the load-serving entity function. The Commission also approved NERC's proposed revisions related to the registration of distribution providers, but directed that NERC must include Reliability Standard PRC-005 (Transmission and Generation Protection System Maintenance and Testing) as applicable to underfrequency load shedding-only distribution providers. Additionally, the Commission directed NERC to modify the Rules of Procedure to provide the Commission with an opportunity to review decisions by the NERC-led review panel in cases where no appeal occurs by notifying the Commission when it posts a NERC-led review panel decision.

4. With regard to removal of the load-serving entity function, the Commission concluded that NERC did not adequately justify eliminating the load-serving entity function and directed NERC to submit within 60 days a compliance filing that addressed the Commission's concerns.[3] Specifically, the Commission requested additional information regarding how: (1) the deactivation of distribution providers with peak load between 25 and 75 MW affects NERC's estimate regarding the number of load-serving entities that would be deregistered; (2) applicable entities will continue to receive necessary load information for balancing and forecasting purposes upon elimination of the load-serving entity registration category; (3) continuity of responsibility under Reliability Standards applicable to load serving entities will be ensured; and (4) deactivating load-serving entities will affect reliability over time in areas facing

[2] March 19 Order, 150 FERC ¶ 61,213 at P 16.

[3] NERC requested an additional 30 days to submit its compliance filing, which the Commission granted on April 20, 2015.

significant load growth.[4] The Commission also sought additional information on NERC's coordination with the North American Energy Standards Board (NAESB) to ensure the timely transfer of commercial-related practices affected by the proposed elimination of the load-serving entity function.[5]

II. NERC Compliance Filing

5. On July 17, 2015, NERC submitted its compliance filing providing additional information, stating that it satisfies the Commission's concerns described in the March 19 Order. In support of its filing, NERC also provides as Exhibit D of its petition an "Analysis Supporting Removal of Load-Serving Entities" (Technical Analysis). NERC states that it developed the Technical Analysis with input from Regional Entities, load-serving entities, reliability coordinators and balancing authorities.

6. Regarding the effect of deactivating distribution providers with peak load between 25 and 75 MW on the number of load-serving entities that would be deregistered, NERC states that out of the 461 registered load-serving entities, 419 will remain registered as another functional category, leaving 41 potential deregistration candidates.[6] NERC states that the 41 potential deregistration candidates include: (1) its estimate of fourteen load-serving entities to be deregistered as set forth in NERC's initial RBR petition; and (2) the potential deactivation of distribution providers with peak load between 25 and 75 MW based on the increase in the general distribution provider registration threshold.

7. With regard to how balancing authorities and reliability coordinators will continue to receive necessary load information for balancing and forecasting purposes, NERC begins by explaining that load-serving entity tasks generally cover two categories of information: ahead-of-time tasks and real-time tasks. According to NERC, ahead-of-time tasks include submission of load profiles and forecasts to balancing authorities, resource planners and transmission planners, arranging for transmission service from transmission service providers, and submitting requests for interchange-to-interchange coordinators. NERC adds that real-time tasks involve receiving requests for voluntary load curtailment and communicating such requests to end-use customers as directed by a balancing authority or distribution provider. NERC states that it has determined that all

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[4] March 19 Order, 150 FERC ¶ 61,213 at PP 38-41, 43.

[5] *Id.* P 42.

[6] According to NERC, the count excludes one entity that will be deregistered separate and apart from the RBR initiative.

41 entities potentially eligible for deregistration as a load-serving entity are subject to applicable market rules, tariffs, and agreements which will ensure the continuation of load-serving entity reliability activities. NERC explains that it focused on the load-serving entity's responsibility for reporting load because this task is covered by NERC Reliability Standard requirements that apply to load-serving entities. NERC evaluated whether the load data collected by load-serving entities would still be provided for under a contractual agreement or other market protocol. NERC represents that it confirmed that all entities participate in an organized market that requires load data to be provided under a market participation agreement or a Commission-approved tariff.

8. NERC provides specific tariff and agreement provisions in Appendix E of Exhibit D of its filing. NERC states that these tariffs and protocols ensure that the load serving entities' ahead-of-time and real-time tasks continue. For example, NERC explains that in the Electric Reliability Council of Texas, Inc. (ERCOT) region - where nearly half (18) of the 41 load-serving entities potentially eligible for deregistration are located - ERCOT protocols call for the development of demand forecasts and load profiles by ERCOT, partly based on the load data research conducted by transmission service providers and distribution service providers. The ERCOT protocols also require load-serving entities to designate a qualified scheduling entity to perform load shedding and interruptible load responsibilities on behalf of the load-serving entity. NERC also explains that five of the 41 are under the California Independent System Operator (CAISO) tariff, where the load serving entity is a metered subsystem which is responsible for balancing its own load and resources within its territory. The CAISO tariff also requires the load-serving entity to coordinate projected load growth for planning purposes. In the same vein, an additional five of the load-serving entities are under the Midcontinent Independent System Operator, Inc. (MISO) tariff, which mandates that transmission operators receive ahead-of-time information, including balancing authority load forecast, day-ahead schedules for all resources, and forecast commitment status, so that the transmission operator can perform local reliability analysis. With respect to real-time data, NERC states that, under the MISO tariff, market participants that are load-serving entities or are purchasing on behalf of a load serving entity must respond to transmission provider directives to curtail load. NERC also includes the remaining entities which are covered by non-ISO or RTO tariffs or agreements.

9. With respect to registered entities that were identified by NERC and the Regional Entities as potentially eligible for removal from the registry criteria, NERC requested that these registered entities provide confirmation of existing contractual obligations or other processes in place through which balancing authorities and reliability coordinators would receive load data. Furthermore, NERC inquired with these entities whether deregistration of their load-serving entity function would change their current processes for providing needed information. According to NERC, the load-serving entities responded that their loads are metered and this information is provided to the balancing authorities in real-time. NERC adds that the 41 entities potentially eligible for deregistration are located in

10 balancing authorities and that it reviewed contractual agreements of these load-serving entities and confirmed that these agreements contain sufficient load data, load forecasting, and load shedding provisions. NERC also independently reviewed potential underlying alternative sources of authority, such as responsibilities of entities that will remain on the compliance registry to cover load-serving entity tasks. Specifically, NERC reviewed: open access transmission tariffs, power purchase agreements, network integration transmission service agreements, operating agreements, ERCOT protocols, market rules and the regulatory framework in Texas, transmission planning data services agreements, and reliability assurance agreements. NERC states that these mechanisms that are already in place further assure that balancing authorities and reliability coordinators will continue to obtain needed information.

10. Further, NERC explains that it surveyed the 18 balancing authorities and reliability coordinators that NERC had identified as having load-serving entities potentially eligible for deregistration, and requested that they review the list of deregistration candidates and the impact on the balancing authority or reliability coordinator's ability to receive metered information. NERC also asked the balancing authorities and reliability coordinators to analyze whether deregistration of the potentially eligible entities would adversely affect their ability to receive such real-time and forecasted load condition data from the same load-serving entities or other entities through other contractual arrangements. According to NERC, all but two entities responded that they have contractual obligations with the relevant load-serving entity. NERC states that of the two that do not, one no longer have entities eligible for registration and the other has agreements with its load serving entities that specify load data sharing and forecasting obligations.

11. NERC also surveyed Regional Entities, balancing authorities, reliability coordinators and entities eligible for deregistration as a result of the proposed elimination of the load-serving entity registration category. NERC states that the surveys requested information on how (1) the deactivation of certain distribution providers affects NERC's estimate regarding the number of load-serving entities that would be deregistered; (2) balancing authorities and reliability coordinators will continue to receive necessary load information for balancing and forecasting purposes upon elimination of the load-serving entity registration category from the compliance registry; (3) continuity of responsibility under Reliability Standards applicable to load-serving entities would be ensured; and (4) deactivating load-serving entities would affect reliability over time in areas facing significant load growth. In addition, NERC states that it asked Regional Entities to review the registration information in their respective footprints regarding all load-serving entities that could be eligible for deregistration as a result of the RBR initiative. NERC states that all eight confirmed the loads of these entities and also verified if distribution providers meeting the peak MW criterion would remain registered as a result of application of other distribution provider registration criteria. NERC also

states that the Regional Entities confirmed the list of potential entities that could be eligible for deregistration.

12. In response to the Commission's concern that NERC did not provide adequate information regarding how certain load-serving entity reliability tasks will be performed going forward, NERC explains that of the 419 entities remaining on the compliance registry, 382 will remain registered as a distribution provider. NERC explains that, of the 38 load-serving entities not also registered as a distribution provider, all but eight are registered as either a balancing authority, generator operator or transmission operator. NERC adds that, of the remaining eight load-serving entities, seven are registered as either a generator owner, transmission owner or resource planner, and they are dispersed through three separate Regional Entity footprints. NERC states that one entity is registered only as a load-serving entity; however, that entity is in the process of deregistration due to no longer performing the function in the region it is registered.[7] NERC states that entities registered for the seven functions are also subject to the Reliability Standard requirements that currently apply to the load-serving entity function. NERC also provides a mapping document showing that, of the 72 Reliability Standard requirements applicable to load-serving entities, 55 are also applicable to distribution providers.[8]

13. NERC states that the 41 entities eligible for potential deregistration represent between 0.3 percent and 3.39 percent of their areas' peak load. NERC explains that there is no concentration of these deregistered entities in any Regional Entity footprint, other than Texas Regional Entity which has 18. NERC adds that, even in the Regional Entity footprint facing the largest load growth (projected at seven percent), the estimate of load-serving entity-only organizations that would be completely removed from the compliance registry account for approximately 0.17 percent of total load. NERC also states that the reliability coordinators and balancing authorities did not identify any concerns with respect to load or forecast changes, mitigation of contingencies, or changes in reserve margins. According to NERC, because the 41 entities represent a small percentage of load, there is little to no risk to reliability associated with their removal as a load-serving entity from the compliance registry.

14. NERC states that it has coordinated with NAESB, assuring NAESB the opportunity to develop business practice standards where appropriate in light of NERC's anticipated elimination of the load-serving entity registration category. NERC states that

[7] NERC Compliance Filing at n. 29.

[8] NERC Compliance Filing, Appendix D of Exhibit D.

it has had extensive discussions with NAESB leadership on whether removal of any of the load-serving entity Reliability Standards warranted development of a NAESB standard. NERC states that NAESB identified Reliability Standard INT-011-1 as a candidate for a standard. NERC states that Reliability Standard INT-011-1 targets older or grandfathered agreements, and none of the entities registered solely for the load-serving entity function have any of these agreements. Further, NERC states that an existing NAESB standard, Electronic Tagging Functional Specification, requires e-tag data to be included for point-to-point transactions including grandfathered agreements. NERC adds that the NAESB Wholesale Electric Quadrant (WEQ) Standards leadership conducted a thorough review and identified Reliability Standard INT-011-1 as a candidate for a commercial process standard. According to NERC, the WEQ Executive Committee Chair and Vice Chair have agreed to submit a request to NAESB to ensure that this commercially-related practice under Reliability Standard INT-011-1 is considered for standards development through the NAESB process.[9]

III. Notice of Filing and Responsive Pleadings

15. Notice of NERC's July 17, 2015 compliance filings was published in the *Federal Register*, 80 Fed. Reg. 44,950 (2015), with interventions and protests due on or before August 17, 2015. American Public Power Association, National Rural Electric Cooperative Association, and Transmission Access Policy Study Group (Joint Commenters) and Dominion Resources Services, Inc. (Dominion) filed timely motions to intervene and comments in support of NERC's filing. On August 18, 2015, MISO filed a motion to intervene out-of-time.

Comments

16. Joint Commenters and Dominion support NERC's compliance filing. Dominion agrees with NERC's rationale for removal of the load-serving entity function. Joint Commenters point to NERC's "comprehensive demonstration" that no material load information gap will be created by removing the load-serving entity function. According to Joint Commenters, in addition to the load information that will continue to be available from load-serving entities through their other registrations, and through tariff and contract

[9] Subsequent to the NERC compliance filing, the WEQ Executive Committee, at its August 18, 2015 meeting, approved modifications to WEQ-004, Coordinate Interchange Business Practice Standards, to require the tagging of Intra-Balancing Authority transactions, which is currently addressed in Reliability Standard INT-011-1. The modified business practice standard was ratified by the WEQ membership on September 18, 2015. https://www.naesb.org/weq/weq_final.asp.

obligations, the Commission's *pro forma* tariff provides the overarching framework that assures that load information is provided to those that own and operate the transmission system, and curtailments and load shedding are implemented, to ensure bulk electric system reliability. Joint Commenters argue that load-serving entity registration for NERC compliance was not and is not necessary to accomplish these objectives.

17. Joint Commenters contend that the *pro forma* tariff, combined with all of the specific agreements detailed by NERC, demonstrates that any residual reliability risk from eliminating load-serving entity registration is *de minimis*.[10] According to Joint Commenters, the *pro forma* tariff ensures the ability of transmission providers to obtain the data they need from their network customers, and most load-serving entities are network customers or network load of network customers. Joint Commenters state that under the *pro forma* tariff, load-serving entities will continue to provide their data to their transmission provider. Joint Commenters explain that the *pro forma* tariff allows all transmission providers to get the data they need from their network customers and to direct load curtailments when needed to ensure system reliability; and the network operating agreement provided for by the *pro forma* tariff covers operations, information sharing, and any other issue that might affect the provision of network service. Specifically, with respect to information sharing, *pro forma* tariff section 31.6 requires the network customer to provide the transmission provider with annual updates of its network load and network resource forecasts, as well as timely written notice of material changes in any other information provided in its application relating to any aspect of its facilities or operations affecting the transmission provider's ability to provide reliable service. Joint Commenters explain that this provision allows the entities that own and operate transmission facilities to obtain information needed for long-term planning. Joint Comments also point to section 33.6 of the *pro forma* tariff, which states that when the transmission provider determines that it is necessary for the transmission provider and network customer to shed load, the parties shall do so in accordance with the network operating agreement; and section 33.7 gives the transmission provider the authority to curtail network transmission service whenever needed to protect reliability.

IV. Commission Determination

A. Procedural Matters

18. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, the timely, unopposed motions to intervene serve to make the entities that filed them parties

[10] Joint Commenters at 11, n.15-17.

to this proceeding.[11] We also accept MISO's untimely intervention given its interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

B. Commission Determination

19. We accept NERC's compliance filing. We find that NERC has complied with the March 19 Order with respect to providing additional information justifying the removal of the load-serving entity function and including Reliability Standard PRC-005 as applicable to underfrequency load shedding-only distribution providers. We also find that NERC's modification to the Rules of Procedure to provide the Commission with an opportunity to review decisions by the NERC-led review panel in cases where no appeal occurs by notifying the Commission when it posts a NERC-led review panel decision is adequate.

20. As we discuss below, we find that NERC has addressed the concerns expressed regarding an accurate estimate of the load-serving entities to be deregistered and the reliability impact of doing so. NERC demonstrates that load data will continue to be available and reliability activities will continue to be performed even after load-serving entities would no longer be registered. We find that NERC has provided adequate additional support in its compliance filing that is responsive to the Commission's concerns described in the March 19 Order, and conclude that the proposed elimination of the load-serving entity function is reasonable. We believe that NERC has demonstrated that the risks posed by the elimination of the load-serving entity functional category registration are likely to be minimal.

21. In the March 19 Order, the Commission noted that eliminating the load-serving entity function does not remove the need to provide information required for reliable operation of the bulk electric system.[12] NERC's compliance filing includes additional information that clarifies whether and how some entities will continue to provide information or who will assume their obligations. For example, NERC notes that the number of affected entities is small, spread across all eight Regional Entity footprints and involves a small percentage of load. In addition, NERC provides explanation and specific tariff and contract language showing how load-serving entities are obligated to continue to provide information and respond to commands from various entities. NERC has also described how the load-serving entities will be required to continue to provide

[11] 18 C.F.R. § 385.214 (2015).

[12] March 19 Order, 150 FERC ¶ 61,213 at P 32.

the information through their responsibilities as other registered functions. NERC has explained which entities will continue to provide this information. Further the responses from reliability coordinators, balancing authorities, Regional Entities, and other affected entities that need the information load-serving entities indicate that these entities do not foresee any concerns if load-serving entities are no longer registered entities. Accordingly, we conclude that NERC and others have provided reasonable support that the elimination of the load-serving entity function will likely have no material impact on the reliability of the bulk electric system.

22. With regard to our concern about the revision of the distribution provider threshold from 25 MW to 75 MW peak load causing an increase in the deactivation of entities that are currently registered as distribution providers,[13] NERC indicates that an additional 27 entities could be deregistered as load-serving entities and below 75 MW distribution providers. Nevertheless, we are persuaded by NERC's technical analysis and mapping document that other functional entities will take on responsibility for compliance with many Reliability Standards currently assigned to load-serving entities. This evidence combined with NERC's specific explanation of and references to tariffs and agreements persuades us that deregistered entities will continue to perform load-serving entity-related activities.

23. In addition, we find that NERC provides adequate information to show that balancing authorities, planners, and other affected entities will continue to have access to the data to estimate demand and energy forecast for areas where the load-serving entity is deregistered. Additionally we note that NERC proposes no changes to the obligations of the balancing authorities and transmission operators to provide operating data to their reliability coordinators pursuant to the applicable Reliability Standards.[14] Further, NERC has adequately demonstrated that in areas of significant load-growth, the cumulative effect on reliability of deregistered entities not having to provide accurate load data projections is not likely to increase over time as load increases. While we believe that NERC has adequately addressed its coordination with NAESB to ensure the timely transfer of commercial-related practices affected by the proposed elimination of the load-serving entity function, because that process remains incomplete we expect NERC to keep Commission staff informed of any developments regarding the appropriate transfer of functions to NAESB.

[13] *Id.* P 39.

[14] *See, e.g.*, Reliability Standard IRO-010-001.

24. We accept NERC's proposal to eliminate the load-serving entity as a registered function subject to the Reliability Standards. As discussed above, we do so, in part, based on NERC's explanation that entities needing information from load-serving entities will continue to receive the data needed to fulfill their operational and planning responsibilities from other registered entities subject to Reliability Standards that currently apply to the load-serving entity function, and from deactivated load-serving entities subject to other arrangements.

25. While NERC has provided adequate support on this matter, we believe that it is prudent for NERC to perform a follow-up analysis to assure that affected transmission operators and balancing authorities remain able to perform reasonably accurate next-day studies. Accordingly, we direct NERC to study and report to the Commission, within 15 months from the date of this order, the extent to which the next-day studies by a representative sample of the affected transmission operators and balancing authorities match or differ from their real-time results and, if there are any significant differences, whether those differences are attributable to the changes authorized here. In performing this analysis, NERC may choose to compare these results to results for the same entities before implementation of these changes, or to results for entities not affected by these changes, or both, if NERC deems it appropriate.

The Commission orders:

(A) The Commission hereby accepts NERC's compliance filing, as set forth in the body of this order.

(B) The Commission directs NERC to submit an informational filing within 15 months of the date of this order, as set forth in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

153 FERC ¶ 61,135
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RR15-12-000

ORDER CONDITIONALLY APPROVING REVISED *PRO FORMA* DELEGATION AGREEMENT AND REVISED DELEGATION AGREEMENTS WITH REGIONAL ENTITIES

(Issued November 2, 2015)

1. On June 26, 2015, North American Electric Reliability Corporation (NERC) petitioned the Commission to approve: (i) a revised *Pro Forma* Delegation Agreement; and (ii) revised Delegation Agreements between NERC and each of the eight Regional Entities.[1] The currently effective Delegation Agreements between NERC and each Regional Entity will expire on December 31, 2015; NERC proposes that the revised Delegation Agreements become effective January 1, 2016.

2. In this order, we conditionally approve the agreements in NERC's petition, to become effective January 1, 2016. As discussed below, the Commission directs NERC to modify the revised *Pro Forma* Delegation Agreement and revised Delegation Agreements and submit a compliance filing to address those modifications within 120 days of the date of this order.

[1] The eight Regional Entities are: Florida Reliability Coordinating Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council, Inc. (NPCC); Reliability*First* Corporation (RFC); SERC Reliability Corporation (SERC); Southwest Power Pool, Inc. (SPP RE); Texas Reliability Entity (Texas RE); and Western Electricity Coordinating Council (WECC).

I. Background

3. On February 3, 2006, the Commission issued Order No. 672[2] to implement the requirements of section 215 of the Federal Power Act (FPA) governing electric reliability.[3] In July 2006, the Commission, pursuant to section 215 of the FPA, certified NERC as the Electric Reliability Organization (ERO).[4] The Commission conditionally accepted NERC's proposal to delegate certain ERO functions to its designated Regional Entities. In addition, the Commission conditionally accepted NERC's proposed *Pro Forma* Delegation Agreement, including the NERC *Pro Forma* Compliance Monitoring and Enforcement Program (CMEP) and CMEP Hearing Procedures.

4. In April 2007, NERC entered into separate Delegation Agreements with eight Regional Entities, through which NERC delegated certain ERO functions. Consistent with Order No. 672, NERC delegated authority to the Regional Entities to audit, investigate, and otherwise ensure that users, owners, and operators of the Bulk-Power System comply with NERC's mandatory Reliability Standards, subject to ERO oversight.[5] Further, the Delegation Agreements addressed: (i) regional Reliability Standards development; (ii) registration of entities that must comply with Reliability Standards; and (iii) other services supporting NERC's functions, including reliability assessments, event analysis, and training and education. The Commission accepted the Delegation Agreements.[6]

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[2] *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).

[3] 16 U.S.C. § 824o (2012).

[4] *North American Electric Reliability Corp*., 116 FERC ¶ 61,062 (ERO Certification Order), *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).

[5] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 654.

[6] *See North American Electric Reliability Corp*., 119 FERC ¶ 61,232 (2007) (accepting executed delegation agreements); *North American Electric Reliability Corp*., 119 FERC ¶ 61,060 (2007).

5. On June 9, 2010, as supplemented on June 17, 2010, NERC filed a petition for the Commission to approve revisions to NERC's Rules of Procedure, the *Pro Forma* Delegation Agreement, Delegation Agreements between NERC and the eight Regional Entities, and bylaws of FRCC and MRO. On October 21, 2010, the Commission conditionally approved NERC's petition and directed NERC to submit a compliance filing containing revisions to the NERC Rules of Procedure, NERC's *Pro Forma* Delegation Agreement, Delegation Agreements between NERC and the eight Regional Entities, and bylaws of FRCC and MRO.[7] NERC submitted a compliance filing, and the Commission accepted the compliance filing on October 7, 2011.[8]

II. NERC Filing

6. In its June 26, 2015 petition, NERC proposes revisions to the *Pro Forma* Delegation Agreement and its attachments and the Delegation Agreements with the eight Regional Entities. NERC requests that the Commission approve its proposals effective January 1, 2016.

7. NERC proposes revisions to the following sections of the *Pro Forma* Delegation Agreement: (i) Definitions (Section 1); (ii) Representations (Section 2); (iii) General Covenants (Section 3); (iv) Development and Proposal of Reliability Standards (Section 5); (v) Enforcement of Compliance with Reliability Standards (Section 6); (vi) Delegation-Related Activities (Section 7); (vii) Oversight of Performance of Delegated Functions and Related Activities (Section 8); (viii) Funding (Section 9); (ix) Term and Termination (Section 12); (x) Confidentiality (Section 15); (xi) Exhibit B – Governance; and (xii) Exhibit C – Regional Standard Development Procedure; and (xiii) Exhibit D – Compliance Monitoring and Enforcement Program.

8. NERC's proposed revisions to the Delegation Agreements with the eight Regional Entities are generally limited to conforming the Delegation Agreements to the language contained in the revised *Pro Forma* Delegation Agreement. Each proposed Delegation Agreement, however, contains deviations from the revised *Pro Forma* Delegation Agreement.

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[7] *North American Electric Reliability Corp.*, 133 FERC ¶ 61,061 (2010), *reh'g denied*, 134 FERC ¶ 61,179 (2011) (2010 Delegation Agreement Order).

[8] *North American Electric Reliability Corp.*, 137 FERC ¶ 61,028 (2011). The Commission has accepted further modifications to some Delegation Agreements since October 7, 2011.

III. Notice and Responsive Pleadings

9. Notice of NERC's filing was published in the *Federal Register*, 80 Fed. Reg. 38,187, 38,188 (2015), with interventions and protests due on or before July 27, 2015. Motions to intervene were timely filed by Idaho Power Company, Avista Corporation, Portland General Electric Company, California Department of Water Resources, Tri-State Generation and Transmission Association, Inc., and Puget Sound Energy, Inc. Joint comments were filed by Avista Corporation, Idaho Power Company, Portland General Electric Company, Puget Sound Energy, Inc., and Tri-State Generation and Transmission Association, Inc. (Joint Commenters). Motions to intervene and comments were timely filed by the American Public Power Association and the Transmission Access Policy Study Group (jointly, APPA and TAPS), and Public Utility District No. 1 of Snohomish County, Washington (Snohomish). A motion to intervene and protest was timely filed by the Large Public Power Council (LPPC).

10. NERC submitted a motion for leave to answer and an answer on August 10, 2015. On August 14, 2015, the Western Interconnection Regional Advisory Body (WIRAB) submitted advice to the Commission pursuant to section 215(j) of the FPA.[9] Joint Commenters and Snohomish moved for leave to answer NERC's answer and filed answers on August 21, 2015.

IV. Procedural Matters

11. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2015), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

12. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2015), prohibits an answer to a protest or an answer, unless otherwise ordered by the decisional authority. We will accept the answers filed because they provide information that assisted us in our decision-making process.

V. Discussion

13. Except as otherwise indicated below, we approve NERC's proposed *Pro Forma* Delegation Agreement and the revised Delegation Agreements between NERC and each of the eight Regional Entities. As indicated by NERC, the revised *Pro Forma* Delegation Agreement and revised Delegation Agreements between NERC and each of the eight Regional Entities are the product of negotiations between NERC and the Regional

[9] 16 U.S.C. § 824o(j) (2012).

Entities, reflecting lessons learned from their experience operating under section 215 of the FPA and the prior Delegation Agreements.[10]

A. Delegation-Related Activities (Section 7)

1. NERC Filing

14. NERC proposes to revise section 7, "Delegation-Related Activities," of the *Pro Forma* Delegation Agreement as follows:

> NERC will engage [Regional Entity] on its behalf to carry out certain of its activities that in furtherance of Bulk-Power System reliability and NERC's responsibilities as the ERO under the Act or in support of the Delegated Authority, as specified in the NERC Rules of Procedure and listed ~~on~~in Exhibit E. NERC may from time to time develop policies or procedures, which shall be used by [Regional Entity] in the performance of the delegation-related activities. These delegation-related activities shall include, but are not limited to, those described in subsection (a) through (~~f~~g), each of which shall be considered a statutory activity.[11]

Section 7 of the *Pro Forma* Delegation Agreement identifies the following delegation-related activities: (a) Certification of Bulk-Power System Entities; (b) Registration of owners, operators, and users of the Bulk-Power System; (c) Reliability Assessment and Performance Analysis; (d) Event Analysis and Reliability Improvement; (e) Training and Education; (f) Situation Awareness; and (g) Critical Infrastructure Security. Section 7 contains only minor revisions from the currently-effective *Pro Forma* Delegation Agreement; namely, separating Situation Awareness and Critical Infrastructure Security into two separate categories, and inserting new language underlined above indicating that NERC may from time to time develop policies and procedures related to certain topics.

15. NERC states that during its stakeholder comment period, stakeholders requested that NERC distinguish in the *Pro Forma* Delegation Agreement "between statutory delegated authority to NERC under Section 215 of the FPA and delegation-related

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[10] NERC Petition, Attachment 2 Redline – Revised *Pro Forma* Regional Delegation Agreement, Preamble.

[11] NERC Petition, Attachment 2 Redline – Revised *Pro Forma* Regional Delegation Agreement, Section 7.

activities performed by the Regional Entities."[12] NERC states that stakeholders also contended that the scope of responsibilities assumed by NERC, and further delegated to the Regional Entities in the Delegation Agreements, extends beyond that contemplated in section 215 of the FPA. NERC states that the scope of NERC's statutory authority under section 215 of the FPA has been previously litigated before the Commission and resolved in the proceedings resulting in the Statutory Criteria Order.[13]

16. NERC states that the definition of "Delegated Authority" in the revised *Pro Forma* Delegation Agreement is not substantively changed from the current Commission-approved *Pro Forma* Delegation Agreement, encompasses authority to propose and enforce Reliability Standards as expressly provided to the ERO in section 215 of the FPA, and provides the Regional Entity authority to "undertake related activities set forth in this Agreement in furtherance of these delegated functions in accordance with the [FPA], the ERO Regulations and this Agreement."[14] NERC states that the Commission concluded in the Statutory Criteria Order that section 215 of the FPA allows "necessary or appropriate" activities in furtherance of the functions specified in section 215.[15] NERC asserts that it believes that all of the "related activities . . . in furtherance of these delegated functions" set forth in the revised *Pro Forma* Delegation Agreement fall within the Commission-approved section 215 written criteria.[16] Further, NERC contends, the revised *Pro Forma* Delegation Agreement does not expand the delegated functions beyond the scope of the delegated functions provided for in the currently effective *Pro Forma* Delegation Agreement, which the Commission approved in the 2010 Delegation Agreement Order.

2. Comments

17. Several commenters raise concern regarding NERC's authority to delegate certain activities to a Regional Entity. Joint Commenters note that section 215 of the FPA and the Commission's regulations state that NERC may delegate authority to a Regional Entity for two discrete functions, i.e., proposing Reliability Standards to the ERO and

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[12] NERC Petition at 10.

[13] *Id.* at 10 (citing *North American Electric Reliability Corp.*, 143 FERC ¶ 61,052 (2013) (Statutory Criteria Order)).

[14] *Id.* (citing section 1(c) of the *Pro Forma* Delegation Agreement).

[15] *Id.* at 11 (citing Statutory Criteria Order, 143 FERC ¶ 61,052 at P 31).

[16] *Id.*

enforcing Reliability Standards. Joint Commenters add that section 215 of the FPA requires NERC to conduct periodic assessments of the reliability and adequacy of the Bulk-Power System; section 215 does not authorize NERC to delegate this function to Regional Entities. Further, Joint Commenters state that section 215 of the FPA provides for NERC to allocate charges among end users for all activities under section 215.

18. Joint Commenters state that WECC's performance of activities falling outside of section 215 of the FPA cannot be funded through statutory funding. Pointing only to information not in the record of the instant proceeding, Joint Commenters allege that WECC engages in planning services, transmission expansion planning, the Western Renewable Energy Generation Information System (WREGIS), and other programs that are neither statutory functions nor appropriate to further WECC's performance of any statutory function.[17] Joint Commenters note that the only program WECC claims is non-statutory is WREGIS. Joint Commenters contend that WECC relies on an overly broad grant of authority in its current Delegation Agreement with NERC to justify funding its activities.[18]

19. Joint Commenters state that the proposed Delegation Agreement with WECC purports to delegate to WECC activities that are neither delegable under section 215 nor statutory functions at all. Specifically, Joint Commenters note that section 7 of the Delegation Agreement with WECC provides that WECC may "carry out certain of its activities that are in furtherance of Bulk-Power System reliability and NERC's responsibilities as the ERO . . . in support of the Delegated Authority, as specified in the NERC Rules of Procedure and listed on Exhibit E" and that each of those activities "shall be considered a statutory activity[.]"[19] Joint Commenters argue that section 7 lists activities that go, or are subject to interpretations that go, beyond the functions that may be delegated to Regional Entities. Joint Commenters argue that to the extent section 7 may include activities that are delegable to WECC under section 215 of the FPA, it is duplicative of the authorizations provided for in sections 4, 5, and 6 of the proposed Delegation Agreement with WECC. Thus, Joint Commenters argue that section 7 of the proposed Delegation Agreement with WECC should be rejected in its entirety.

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[17] Joint Commenters Comments at 5-6.

[18] *Id.* at 7 (citing WECC Response to Stakeholder Comments – 2016 Draft Business Plan and Budget [June 5, 2015] at 3).

[19] *Id.* at 8 (citing WECC Delegation Agreement at 9).

20. However, Joint Commenters also state that "even assuming without conceding that the Section 7 Activities are within the scope of functions that may be delegated to Regional Entities, including WECC, Section 7 of the Delegation Agreement with WECC does not provide sufficient definition of those Section 7 Activities."[20] Joint Commenters argue that the section 7 language – providing that delegation-related activities "shall include, but are not limited to, those described in subsections (a) through (g), each of which shall be considered a statutory activity" – creates an opportunity to expand the scope of the proposed Delegation Agreement with WECC without oversight or Commission review and approval.[21] Joint Commenters conclude that, at a minimum, NERC and WECC should be required to clearly articulate the activities to be performed, and funded, as statutory activities pursuant to section 215 of the FPA.

21. LPPC raises a concern with the open-ended nature of the list of activities in section 7 (i.e., "these delegation-related activities shall include, but are not limited to"). LPPC states that "although it does not quarrel with the list of activities NERC provides [in section 7 of the revised *Pro Forma* Delegation Agreement], it must either be an exclusionary list or affirmatively restricted to NERC's statutory responsibilities and those that may be delegated under the statute."[22]

22. LPPC notes that its members expressed concern that certain Regional Entities may propose being involved in regional planning activities and in the administration of energy markets. LPPC states that it understands Regional Entities may undertake responsibilities independent of the delegated functions, but contends it must be clear these functions are independent of the ERO and not eligible for funding pursuant to section 215 of the FPA.[23]

23. LPPC concludes that its concern is that the proposed *Pro Forma* Delegation Agreement fails to express NERC's intention to restrict the Regional Entities to statutorily authorized activities. LPPC suggests that the Commission issue an order

[20] *Id.* at 16.

[21] *Id.* at 16. The language cited by Joint Commenters is identical to that in the *Pro Forma* Delegation Agreement quoted above at P 14.

[22] LPPC Comments at 3.

[23] *Id.* at 4.

ensuring that delegation may not exceed the scope of activity contemplated under the statute.[24]

24. Snohomish contends that the proposed *Pro Forma* Delegation Agreement should make clear that delegation-related activities described in sections 5, 6, and 7 do not include administration of transmission planning activities (e.g., a regional transmission planning process under Order No. 1000),[25] or commercial activities (e.g., an energy market), as Snohomish argues that these activities are beyond the scope of section 215 of the FPA.[26] Snohomish contends that these exclusions will clarify the funding mechanisms that should be used at a time when Regional Entities are increasingly being asked to perform more activities. Snohomish states, for example, that entities in the WECC footprint have suggested that WECC take a larger role in the development of energy markets in the Western Interconnection, while others have suggested that WECC undertake transmission planning obligations under Order No. 1000. Snohomish notes that it is not aware of any Commission-regulated energy market that is statutorily funded, and that allowing a Regional Entity to use statutory funding to administer an energy market would be inconsistent with how other energy markets are funded.

25. Snohomish states that, under the proposed *Pro Forma* Delegation Agreement, such activities are not explicitly excluded unless an individual Regional Entity lists them as non-statutory activities in Exhibit E of its Delegation Agreement.[27] As an example, Snohomish notes that Exhibit E of the proposed Delegation Agreement with NPCC states that NPCC does not conduct resource or transmission planning. Snohomish requests that, rather than allowing a Regional Entity and NERC to decide whether administering transmission planning or commercial activities is non-statutory, the Commission direct NERC to explicitly state so in the revised *Pro Forma* Delegation Agreement.

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[24] *Id.* at 5.

[25] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014) (Order No. 1000).

[26] Snohomish Comments at 1, 3.

[27] *Id.* at 3.

3. Answers and Replies

26. NERC responds that it is unnecessary and unduly restrictive to require an exhaustive, all-inclusive list of activities that may or may not be eligible for statutory funding in the revised *Pro Forma* Delegation Agreement. NERC states that the annual business plan and budget process provides an opportunity for the Commission to review each Regional Entity's proposed activities and related costs and determine whether they are eligible and appropriate for funding under section 215 of the FPA. WIRAB concurs with these statements and requests the Commission approve the proposed *Pro Forma* Delegation Agreement and Delegation Agreement with WECC as filed, as WIRAB states this approval would be consistent with section 215 of the FPA and prior Commission orders.[28]

27. NERC contends that the delegation-related activities listed in section 7 of the proposed *Pro Forma* Delegation Agreement are all activities that fall within NERC's Commission-approved criteria for statutory funding.[29] NERC notes that the language in section 7, providing that the delegation-related activities "are not limited to" the list in that section, appears in all eight Delegation Agreements and was approved by the Commission in earlier versions of the Delegation Agreements. NERC adds that it, or the Regional Entities, cannot use section 7 to unilaterally expand the list of activities that a Regional Entity can perform and be funded under section 215 of the FPA because such activities must be submitted and approved through the annual business plan and budget process.[30] Thus, NERC argues it is unnecessary to include an exclusive list of delegation-related activities in the *Pro Forma* Delegation Agreement.

28. NERC notes that some commenters' concerns appear to arise from discussions regarding WECC's potential involvement in Order No. 1000-related activities, and argues that these issues should be treated as outside the scope of this proceeding. NERC notes that neither LPPC's nor Snohomish's comments reference any proposal from WECC.

29. NERC states that confirmed non-statutory activities are described in Exhibit E of individual Delegation Agreements, to ensure that such activities do not compromise the Regional Entity's oversight role or independence.

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[28] WIRAB Advice at 1.

[29] NERC Answer at 5.

[30] *Id.*

30. Joint Commenters assert in their reply that the Commission should ensure that WECC's statutorily-funded activities are not impermissible expansions of the functions that are properly delegated to WECC. Specifically, Joint Commenters state, the Commission's review should ensure that the Delegation Agreement with WECC is properly tailored to provide clear guidance to allow the Commission, NERC, and the industry to readily identify what should be funded under section 215 of the FPA and what should not. Joint Commenters add that, while the annual business plan and budget process should independently ensure that only those functions that are properly delegated to a Regional Entity are included in WECC's statutory budget, that review does not eliminate the need for the Commission to ensure that the Delegation Agreement with WECC complies with section 215 of the FPA. Joint Commenters note that WECC provides on its website written criteria for determining whether an activity is eligible to be funded under section 215 of the FPA, which include any activity necessary or appropriate for compliance with the Delegation Agreement with WECC. Thus, Joint Commenters request the Commission reject the Delegation Agreement with WECC or at least the non-conforming parts thereof.

31. Snohomish argues that the annual business plan and budget process is not the appropriate place to deal with funding issues under section 215 of the FPA, as a Regional Entity's ability to statutorily fund an activity stems from its authority under its Delegation Agreement. Snohomish contends that if a Delegation Agreement can be read to allow the Regional Entity to engage in an activity, then it would follow that the activity would qualify for statutory funding. Thus, Snohomish states that challenges to fundamental statutory funding issues must be addressed in the instant proceeding.[31]

32. Snohomish notes that NERC does not object to LPPC's request that the *Pro Forma* Delegation Agreement be modified to specify that delegation is limited to NERC's statutory functions.

4. Commission Determination

33. We find that the categories of delegation-related activities set forth in section 7 of the proposed Delegation Agreements are just and reasonable and that delegation of these activities to a Regional Entity by NERC is consistent with Commission precedent. The Commission previously addressed in various contexts both the scope of statutory activities under section 215 of the FPA for funding purposes, as well as activities that are subject to delegation to a Regional Entity. In an October 2006 order approving the NERC and Regional Entity 2007 annual business plans and budgets, the Commission stated that "Regional Entities are entitled to receive funding under section 215 of the FPA

[31] Snohomish Answer at 2.

for functions covered by section 215 . . . , such as the development of Reliability Standards and their enforcement, and monitoring the reliability of the [B]ulk-[P]ower [S]ystem."[32] In the 2007 Budget Order, the Commission also approved the Regional Entity budget categories, which are consistent with the NERC categories and the activities delegated to the Regional Entities in the current and proposed *Pro Forma* Delegation Agreement.[33] The Commission also concluded in the 2007 Budget Order that activities that are found to be statutory under section 215 of the FPA for NERC are statutory activities for the Regional Entities.[34]

34. Additionally, in the 2010 Delegation Agreement Order, the Commission approved NERC's revised *Pro Forma* Delegation Agreement, which expanded the description of section 7, "Delegation-Related Activities," to its current form, including the list of delegated activities, as well as the "but are not limited to" phrase to which LPPC and Joint Commenters now object.[35] While the Commission conditionally approved the so-revised (and now-current) *Pro Forma* Delegation Agreement, no stakeholders provided

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[32] *North American Electric Reliability Corp.*, 117 FERC ¶ 61,091, at P 31 (2006), *order on rehg*, 118 FERC ¶ 61,111, *order on reh'g*, 119 FERC ¶ 61,059 (2007) (2007 Budget Order); *see also* ERO Certification Order, 116 FERC ¶ 61,062 at P 185 (stating that the NERC budget proceeding is the appropriate forum to address issues of whether certain activities identified in the Delegation Agreements are within the scope of section 215 of the FPA).

[33] 2007 Budget Order, 117 FERC ¶ 61,091 at P 32.

[34] 2007 Budget Order, 117 FERC ¶ 61,091 at P 38. The Commission stated:

> NERC has proposed that funded statutory activities be consistent as between the ERO and each Regional Entity. We support NERC's proposal in this regard . . . . NERC's proposed activities are the same that we find to be within the ambit of FPA section 215 and thus entitled to receive funding pursuant to section 215 of the FPA for the ERO and should be statutory in the context of the Regional Entities. We see no reason why they would differ on a regional basis.

Id.

[35] *See* 2010 Delegation Agreement Order, 133 FERC ¶ 61,061.

comments regarding the section 7 delegation-related activities and no modifications to section 7 were required.

35. In the Statutory Criteria Order, the Commission explained:

> The proposed criteria identify categories of activities that are eligible for funding pursuant to FPA section 215. While we approve NERC's proposed criteria with modifications, our determination does not mean that the Commission must accept future NERC business plans and budgets that are based on the application of NERC's proposed criteria. Instead, as in past budget cycles, *the Commission's determination regarding the appropriateness of NERC's activities and funding request will be made in the annual NERC business plan and budget proceedings*.[36]

36. We find that the categories of delegation-related activities set forth in section 7 of the proposed *Pro Forma* Delegation Agreement and in the eight proposed Delegation Agreements are just and reasonable, and delegation of these activities by NERC to a specific Regional Entity, such as WECC, is consistent with Commission precedent. Furthermore, we find that concerns regarding statutory funding of specific activities within these categories are more appropriately addressed in NERC's annual business plan and budget proceedings. This approach is consistent with prior Commission orders.[37]

37. Additionally, we do not find it reasonable to require NERC to list specific activities that are not delegable in the *Pro Forma* Delegation Agreement. Instead, we find it appropriate that the Delegation Agreements provide the types of activities that are delegable to Regional Entities and that the annual business plan and budget filings provide an opportunity to review specific programs and activities that each Regional Entity proposes under those categories of delegated activities. Further, we note that commenters express concern regarding Regional Entities' potential involvement in regional planning activities under Order No. 1000 and in the administration of energy markets. However, commenters in this proceeding do not provide any specific example or evidence of a Regional Entity currently undertaking activities that might fall outside

[36] Statutory Criteria Order, 143 FERC ¶ 61,052 at P 28 (footnotes omitted) (emphasis added).

[37] We note that Joint Commenters and Snohomish filed similar pleadings in the 2016 annual business plan and budget proceeding in Docket No. RR15-16-000.

the scope of section 215 of the FPA. Rather, commenters discuss activities that Regional Entities, in particular WECC, have been asked to perform or may perform in the future.

38. With regard to the specific activities commenters raised, such as transmission planning and commercial activities, we do not find it appropriate to require such broad items to be explicitly excluded from the list of delegation-related activities in the *Pro Forma* Delegation Agreement. While we agree that these activities, in general, may not fall under section 215 of the FPA, tasks related to these activities that a Regional Entity could perform for purposes of Bulk-Power System reliability may be justifiable for funding under section 215. Because such specific tasks, let alone any proposal to fund them, are not before us here, we defer any such ruling to consideration in an annual business plan and budget filing in which a Regional Entity proposes to undertake tasks related to such activities.[38]

B. Oversight of Performance of Delegated Functions and Related Activities (Section 8)

1. NERC Filing

39. NERC proposes to consolidate the provisions in section 8 of the *Pro Forma* Delegation Agreement regarding NERC's oversight of the Regional Entities. In connection with this consolidation, NERC proposes to remove current section 6(i), which requires NERC to audit Regional Entity CMEP activities at least every five years. NERC states that "[i]nstead, this audit requirement, pursuant to section 402.1.3 of the NERC Rules of Procedure, will be encompassed in revised section 8(f), which provides for NERC reviews of the Regional Entity's performance of all delegation-related activities, not just CMEP activities."[39]

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[38] *See North American Electric Reliability Corp.*, 152 FERC ¶ 61,134, at PP 57, 58 (2015) (accepting the 2016 NERC business plan and budget).

[39] NERC Petition at 15. Section 402.1.3 of the NERC Rules of Procedure provides that "[a]t 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. . . ." (emphasis added). Section 1207 of the NERC Rules of Procedure (entitled "Regional Entity Audits") states that "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 [D]elegation [A]greement . . . ."

40. Current section 6(i) of the *Pro Forma* Delegation Agreement states:

> (i) As often as NERC deems necessary, but no less than every five years, NERC shall review [REGIONAL ENTITY]'s compliance monitoring and enforcement program to determine that: (i) the program meets all applicable legal requirements; (ii) actual practices reflect the requirements; and (iii) the program administered pursuant to the Delegated Authority promotes consistent interpretations across North America of Reliability Standards and comparable levels of sanctions and penalties for violations of Reliability Standards constituting comparable levels of threat to reliability of the Bulk-Power System.[40]

41. NERC proposes revisions to sections 8(f)-(g) of the *Pro Forma* Delegation Agreement as follows:

> (f) ~~Any audits~~NERC may perform reviews of [REGIONAL ENTITY] ~~performed by NERC shall be limited~~on a reasonable periodicity to ~~an examinationof~~determine [REGIONAL ENTITY]'s compliance with this Agreement, any policies or procedures established by NERC, NERC's Rules of Procedure, the Compliance Monitoring and Enforcement Program, Commission requirements, and directives that are in effect pursuant to Section 8(c)~~.~~ and to monitor the implementation of guidance and directions issued by the NERC Board of Trustees pursuant to Section 8(d). All such periodic reviews shall comply with the NERC Rules of Procedure and Commission directives.
>
> (g) The Commission and the Commission staff shall have full access to action plans and remedial actions, directives, and directions and guidance issued pursuant to subsections (a)(iii), (c)(iv) and (d), respectively, that are maintained as non-public.[41]

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[40] NERC Petition, Attachment 2 Redline – Revised *Pro Forma* Regional Delegation Agreement, Section 6(i).

[41] NERC Petition, Attachment 2 Redline – Revised *Pro Forma* Regional Delegation Agreement, Section 8(f)-(g).

2. Comments

42. APPA and TAPS express concern regarding NERC's proposal to replace the current section 8(f) audit provisions with new language that provides for "reviews . . . on reasonable periodicity."[42] Further, APPA and TAPS express concern with the removal of section 6(i), which currently requires NERC to review each Regional Entity's CMEP activities at least once every five years.[43]

43. APPA and TAPS contend that the revisions in the *Pro Forma* Delegation Agreement tip the power balance away from NERC and its ability to ensure the consistent implementation of ERO authority that Congress envisioned in allowing for delegation to Regional Entities, and are contrary to the Order No. 672 language favoring a "strong" ERO.[44] Specifically, APPA and TAPS note that the Commission stated in Order No. 672 that "[t]he Commission concludes that a strong ERO . . . is the preferred model for ensuring Bulk-Power System reliability[;]" Order No. 672 "establishes that, in general, the Commission oversees the ERO and the ERO oversees any approved Regional Entity[;]" and "[t]he ERO must periodically audit each Regional Entity's compliance with relevant statutory and regulatory criteria for becoming a Regional Entity and performance in enforcing Reliability Standards and report the results to the Commission."[45] APPA and TAPS state that only with a strong ERO can the Commission achieve the consistency in implementing ERO authority it demanded in Order No. 672 and through years of implementing section 215 of the FPA.

3. Answers

44. NERC asserts that its proposed revisions to the *Pro Forma* Delegation Agreement enhance the ERO's ability to exercise oversight over the Regional Entities and streamline the ability of the ERO to issue a directive to a Regional Entity. NERC notes that the requirement for it to audit the Regional Entities has not been eliminated, and remains in NERC's Rules of Procedure at section 402.1.3. NERC observes that section 8(f) of the proposed *Pro Forma* Delegation Agreement provides that all such periodic reviews, not

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[42] APPA and TAPS Comments at 4.

[43] *Id.*

[44] *Id.* at 5.

[45] *Id.* at 5-6 (citing Order No. 672, FERC Stats. & Regs. ¶ 31,204 at PP 57, 654, 772).

just CMEP audits, must continue to comply with the NERC Rules of Procedure and Commission directives.

45. NERC states that the proposed *Pro Forma* Delegation Agreement reflects the ERO's current oversight and monitoring of Regional Entities, which occurs on a continuous basis and as frequently as reasonably required. Additionally, NERC notes, the proposed *Pro Forma* Delegation Agreement is updated to include additional oversight tools and areas of compliance in the form of guidance, policies, and procedures. NERC adds that the proposed *Pro Forma* Delegation Agreement strengthens NERC's authority by streamlining the directive process and eliminating the ability to appeal a proposed directive to the NERC president.[46]

4. Commission Determination

46. We agree with NERC that the proposed revisions to the *Pro Forma* Delegation Agreement should enhance the ERO's ability to exercise oversight over the Regional Entities and streamline the ability of the ERO to issue a directive. However, we are also concerned that the proposed revisions to section 8(f) and elimination of section 6(i) of the *Pro Forma* Delegation Agreement remove any reference in the *Pro Forma* Delegation Agreement to NERC's obligation to "audit" the Regional Entities, specifically the audit of Regional Entities' CMEP activities at least every five years.

47. As NERC states, current section 6(i) provides for a "review" of a Regional Entity's compliance monitoring and enforcement program activities at least every five years pursuant to the audit requirement of section 402.1.3 of the NERC Rules of Procedure. Current section 8(f) is the section of the *Pro Forma* Delegation Agreement that now refers to NERC "audits" of the Regional Entities. However, unlike current section 6(i), current section 8(f) does not refer to a specific time frame by which NERC must conduct these "audits." The current reference to audits performed by NERC in section 8(f) of the *Pro Forma* Delegation Agreement and the five year requirement in current section 6(i), provide important oversight functions. The Commission is concerned that removal of the word "audits" from section 8(f) of the *Pro Forma* Delegation Agreement in favor of a statement that NERC "may" perform "reviews" with a "reasonable periodicity" could result in confusion or disagreements regarding NERC's responsibility to audit each Regional Entity at least every five years. For this reason, retaining a reference to "audits" in section 8(f) is appropriate.

[46] NERC Answer at 7.

48. However, we are also cognizant that "audits" are a type of "review" in the context of the ERO enterprise, albeit subject to applicable auditing standards and specific procedures, and NERC may wish to perform other types of reviews on a more flexible basis than a typical audit schedule.[47] Therefore, it is appropriate for NERC to perform reviews on a reasonable periodicity in addition to conducting the audits required in the NERC Rules of Procedure. Accordingly, we direct NERC to revise section 8(f) of the *Pro Forma* Delegation Agreement to insert "and audits" after "reviews" where the latter term appears in proposed section 8(f). We also direct NERC to replace the term "may" with "shall" in the first sentence of section 8(f) of the *Pro Forma* Delegation Agreement. These revisions will ensure that the *Pro Forma* Delegation Agreement accounts for the required NERC audits of Regional Entities in accordance with the NERC Rules of Procedure and provides NERC the flexibility to perform reviews it deems necessary on a reasonable periodicity.

49. We are also concerned that neither proposed section 8(f) nor section 8(g) mention Commission access to NERC "reviews" of Regional Entities to be conducted under proposed section 8(f). We believe that the Commission should have access to any NERC reviews and audits of Regional Entity compliance with the policies and procedures listed in section 8(f). In the 2010 Delegation Agreement Order, which conditionally approved the current Delegation Agreements, the Commission directed NERC to insert section 8(g) into the *Pro Forma* Delegation Agreement in order to clarify that the Commission has full access to the non-public information relating to a procedure conducted pursuant to subsections (a)(iii), (c)(iv), or (d) of section 8 of the *Pro Forma* Delegation Agreement.[48] We believe that, without modification, section 8(g) of the proposed *Pro Forma* Delegation Agreement may not grant the Commission sufficient access to NERC reviews (and audits) of the Regional Entities. Without access to that information, Commission oversight of the ERO enterprise would be limited, and the ERO would be less accountable to the public. For this reason, we direct NERC to revise section 8(g), similar to the 2010 Delegation Agreement Order, to explicitly reference the audits and reviews conducted pursuant to section 8(f) in order to grant the Commission full access to the non-public material resulting from these activities.[49]

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[47] *See* sections 402.1.3, 1207 and Appendices 4A, 4C of the NERC Rules of Procedure.

[48] 2010 Delegation Agreement Order, 133 FERC ¶ 61,061 at P 19.

[49] If NERC or a Regional Entity asserts that any responsive materials are confidential or constitute Critical Energy Infrastructure Information, the Commission and its staff will treat such materials as non-public, as set forth in sections 388.112 and 388.113 of its regulations. 18 C.F.R. §§ 388.112-.113 (2015).

C. Term and Termination (Section 12)

1. NERC Filing

50. NERC proposes to revise section 12(b) of the *Pro Forma* Delegation Agreement to provide for an initial five-year term for the Delegation Agreements ending on December 31, 2020 that automatically renews for one additional five-year term ending on December 31, 2025, unless either party provides written notice of termination no later than one year prior to the end of the initial five year term.

51. NERC states that it and the Regional Entities intend for the *Pro Forma* Delegation Agreement to serve as a streamlined, flexible, and forward-looking document that does not require substantial revisions at the expiration of each term, and that changes in the ERO enterprise's strategic plan and programmatic focus should be reflected in the NERC Rules of Procedure and in NERC policies and procedures.[50] NERC states that given this new direction and the limited changes expected for Delegation Agreements year to year, NERC and the Regional Entities propose an initial five-year term with an automatic five-year renewal for the Delegation Agreements. NERC states that this is a typical renewal provision in contracts and allows parties to seek to renegotiate provisions at the end of the five-year term by exercising the notice of termination provision one year in advance of the expiration of the term.

52. The currently effective section 12(b) of the Delegation Agreements requires that NERC shall conduct an audit pursuant to subsection 6(i) of the Delegation Agreement to ensure that the Regional Entity continues to meet all applicable statutory and regulatory requirements necessary to maintain eligibility for delegation before renewing the Delegation Agreement for another five-year term. NERC proposes to eliminate this provision. NERC states this provision is unnecessary given NERC's continuous oversight of the Regional Entities and the current sequence of completing the five-year ERO performance assessments in relation to the expiration of the end of the five-year term of the Delegation Agreement.[51] NERC states that a review of the Delegation Agreement provisions and the Regional Entities' compliance with the Delegation Agreements will be a component of future ERO performance assessments.

[50] NERC Petition at 20.

[51] *Id.* at 20-21.

2. Comments

53. APPA and TAPS stress the importance of close Commission scrutiny of the proposed *Pro Forma* Delegation Agreement, noting that the proposed automatic extension provision could make this the last time that the Delegation Agreements, which form the foundation for the NERC-Regional Entity relationship, are presented to the Commission for review and approval until 2025.[52] APPA and TAPS state that ten years is a long time for a young and still evolving organization with a crucial reliability mission, and the proposed automatic renewal provision highlights the need to ensure the proposed *Pro Forma* Delegation Agreement achieves the strong ERO the Commission intends.

54. APPA and TAPS urge that the Commission make clear its expectation that NERC will exercise its authority under the proposed Delegation Agreements to ensure NERC and the Regional Entities operate in accordance with the strong ERO scheme established in Order No. 672. APPA and TAPS state that, at a minimum, the Commission should preserve its ability to review the Delegation Agreements at the end of the initial five-year term (e.g., by requiring modifications to section 12(b)).

3. Answers

55. NERC responds that the proposed automatic renewal provision does not prevent the Commission from examining the operations of the ERO and Regional Entities for a ten-year period; rather, NERC notes it has committed to its Board of Trustees to review the Delegation Agreements as part of the five-year ERO performance assessment due to be filed in July 2019.[53] NERC states that the review of this report will provide the Commission with the opportunity to review the Delegation Agreements.

56. NERC contends that, if the Commission identifies any opportunities for improvement of the Delegation Agreements in its order on the 2019 performance assessment, NERC and the Regional Entities will have sufficient time to issue notices to terminate the Delegation Agreements and prevent the triggering of the automatic renewal, to instead develop revised Delegation Agreements that address the Commission's directives or concerns.

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[52] APPA and TAPS Comments at 6-7.

[53] NERC Answer at 7.

4. Commission Determination

57. We note that NERC replaced much of the programmatic detail in previous versions of the Delegation Agreement with references to the NERC Rules of Procedure, Regional Entity Rules, and other ERO enterprise policies and procedures. Many of the streamlining revisions represent an improvement as they promote efficiency and flexibility. However, we agree with APPA and TAPS that NERC's proposed revision to section 12(b) would make it possible for ten years to elapse without a requirement that NERC and the Regional Entities present the Delegation Agreements in their entirety to the Commission for review. This is a period longer than the time between the Commission's certification of NERC as the ERO in 2006 and the present, during which substantial changes have occurred in the programs and operations of NERC and the Regional Entities.

58. The proposed revisions to the *Pro Forma* Delegation Agreement may be less extensive than previous revisions, as NERC maintains; however, we believe that the revisions are significant and reflect how the relationship between NERC and the Regional Entities has developed over the last five years. We have no reason to expect that the changes over the next five years will be any less significant. For example, NERC has recently launched initiatives, such as the implementation of the risk-based CMEP and the risk-based registration program, which may result in significant and potentially unforeseeable organizational or operational changes over the next five to ten years. NERC, the Regional Entities, or the Commission may find that further revisions to the Delegation Agreements are needed to account for or address these changes.

59. Given the current revisions and the history of revisions that NERC has proposed to the Delegation Agreements, we direct NERC to modify the *Pro Forma* Delegation Agreement and specific Delegation Agreements with each Regional Entity by removing the automatic renewal provisions, such that the Delegation Agreements are subject to our re-evaluation and re-approval following the initial term, scheduled to end on December 31, 2020. This re-evaluation and re-approval will provide the Commission, NERC, and the Regional Entities with an opportunity to consider whether and, if so, what revisions to these agreements may be appropriate in light of developments during the five-year term, including the results of the Commission's evaluation of the ERO's five-year performance assessment to be filed in 2019.

60. NERC is required to evaluate the effectiveness of each Regional Entity's performance of its delegated functions and provide recommendations for improvement as part of its five-year assessments.[54] We agree with NERC that part of this evaluation

[54] 18 C.F.R. § 39.3(c)(1)(iii) (2015).

should include a review of the Delegation Agreements and the Regional Entities' compliance with the Delegation Agreements. However, we do not believe that the Commission's review of the five-year assessment should replace the formal review of the *Pro Forma* Delegation Agreements and the Delegation Agreements with the Regional Entities. The Commission's orders on the performance assessments provide an opportunity to direct NERC to address operational challenges and identify whether those changes should include changes to the Delegation Agreements with the Regional Entities. However, in light of recent significant NERC initiatives, the continual evolution of the ERO enterprise, and the importance of the Delegation Agreements in ensuring appropriate oversight of the Regional Entities, we conclude that the Commission should continue to review the Delegation Agreements separately from the five-year assessment.

61. NERC also proposes to eliminate the audit provisions of section 12(b) of the Delegation Agreements. As discussed above in the determination regarding the section 8 audit language, we believe the audit provisions in the *Pro Forma* Delegation Agreement provide an important oversight function. Section 402.1.3 of the NERC Rules of Procedure requires NERC to audit a Regional Entity's CMEP at least every five years.[55] Pursuant to section 1207 of the NERC Rules of Procedure, "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."[56] We believe the Delegation Agreements should require similar audit provisions as the NERC Rules of Procedure to ensure NERC performs the necessary audits required by the NERC Rules of Procedure. Therefore, we disagree with NERC that the audit provisions in section 12(b) are unnecessary, and we find that NERC has not sufficiently supported the deletion of the audit provisions in section 12(b).

62. Accordingly, we direct NERC to submit a compliance filing within 120 days of the date of this order, revising section 12 of the *Pro Forma* Delegation Agreement by removing the proposed automatic renewal provisions and by re-inserting the audit provisions in section 12(b) that NERC proposes to eliminate. In this filing, NERC must also replace the references in section 12(b) to audits "pursuant to subsection 6(i)" with a reference to audits "pursuant to the audit requirements of the NERC Rules of Procedure" because the Commission is approving the deletion of section 6(i) in the Delegation Agreements.

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[55] *See supra* n.39.

[56] *See id*.

63. We also note that one rationale for NERC's proposed automatic renewal provision is that NERC believes the streamlined, forward-looking *Pro Forma* Delegation Agreement will require minimal or no revisions at the end of the initial five-year term. Nothing in our determination prohibits NERC from submitting to the Commission a petition to renew the Delegation Agreements and justifying why minimal or no changes are necessary.

D. Regional Entity Bylaws (Exhibit B) and Regional Standard Development Procedure (Exhibit C)

1. NERC Filing

64. NERC proposes to revise the Delegation Agreements to eliminate inclusion of the exhibits that contain the relevant Regional Entity's bylaws and regional standard development procedures. NERC states that there is an administrative efficiency benefit to eliminating copies of the bylaws and regional standard development procedures from the Delegation Agreements, because if a Regional Entity amends its bylaws or its regional standard development procedure, the amendment need only be submitted to the NERC Board and then to the Commission for approval as an amendment to a Regional Entity Rule, rather than an amendment to the Regional Entity's entire Delegation Agreement.[57]

65. NERC states that revised Exhibit B of the Delegation Agreements would continue to provide criteria for bylaw provisions pertaining to corporate governance consistent with section 215(e) of the FPA, noting that section 2(a)(i) of the revised Delegation Agreements states that no other corporate governance documents will be inconsistent with these criteria. Further, NERC notes that language in section 5(a)(ii) of the revised Delegation Agreements provides that the Regional Entity's regional standard development procedure will be consistent with the NERC Rules of Procedure (e.g., Appendix 3A of the NERC Rules of Procedure, the "Standards Process Manual," which provides a comprehensive set of rules for development of standards) and Commission directives.

66. NERC explains that Regional Entity bylaws and regional standard development procedures will continue to be recognized as Regional Entity Rules under section 215(f) of the FPA and any amendments to them will require approval of the NERC Board of Trustees and the Commission. NERC also proposes to add new section 3(b) of the *Pro Forma* Delegation Agreement that specifies that a Regional Entity shall provide NERC with a copy of its Regional Entity Rules upon NERC's request.

[57] NERC Petition at 11-12 & n.30.

2. Commission Determination

67. We find it appropriate to eliminate the requirement that each Regional Entity's bylaws and regional standard development procedure be part of its Delegation Agreement. In the past, this requirement resulted in NERC filing entire Delegation Agreements with the Commission on a regular basis, often due to only a few minor changes in a Regional Entity's bylaws. We believe that separating these documents will increase efficiency and streamline the Delegation Agreements.

68. We are concerned, however, with how NERC and the Regional Entities intend to maintain the Regional Entity bylaws and regional standard development procedures if they are removed from the Delegation Agreements. NERC argues that:

> The decision not to include the Regional Entity's bylaws and [Regional Reliability Standards development procedure] as exhibits to the [Delegation Agreements] does not change each Regional Entity's obligation to develop or *to maintain* these documents, as permitted by FPA 215. The Regional Entity's bylaws and [Regional Reliability Standards development procedure] remain "Regional Entity Rules" as defined in the Commission's ERO regulations; accordingly, a Regional Entity must still obtain NERC and Commission approval of changes to these documents before they take effect.[58]

69. NERC also proposes to add new section 3(b) to the *Pro Forma* Delegation Agreement that states "[Regional Entity] shall provide NERC with a copy of its Regional Entity Rules upon request by NERC." Proposed section 3(b) suggests that NERC does not intend to maintain the Regional Entity bylaws and regional standard development procedures on its website as it currently does with the Delegation Agreements. Instead, section 3(b) suggests that NERC intends to let the Regional Entities maintain the documents separately and provide NERC with the documents upon request. However, we believe that providing access to each Regional Entity's bylaws and regional standard development procedures through a central, easily accessible location on NERC's website will provide important transparency benefits for the public.

70. Thus, we direct NERC to include in its compliance filing a revision to proposed section 3(b) of the Delegation Agreements to include a provision requiring NERC to maintain on its public website the currently effective versions of all of the Regional Entities' bylaws and regional standard development procedures. We also reiterate that all

[58] *Id.* at 12 (emphasis added).

Regional Entity Rules, such as the Regional Entity bylaws and regional standard development procedures, must be filed with and approved by the Commission before they become effective.

E. Enforcement of Compliance with Reliability Standards (Section 6)

1. NERC Filing

71. Section 6 of the *Pro Forma* Delegation Agreement pertains to compliance monitoring and enforcement. NERC proposes to delete sections 6(b)–(f) from the currently-effective Delegation Agreements. According to NERC, these provisions are either out-of-date or duplicative of compliance monitoring and enforcement provisions in the NERC Rules of Procedure, including Appendix 4C, the Uniform Compliance Monitoring and Enforcement Program. NERC avers that the proposed changes do not alter NERC's authority to review and approve a Regional Entity's disposition of noncompliance with Reliability Standards or NERC's oversight authority. NERC states that the intent of the revisions to section 6 is to accommodate future changes in the CMEP practices and procedures without also amending the Delegation Agreements with the Regional Entities.[59]

72. NERC also proposes the following new sections 6(c) and (d) in the revised *Pro Forma* Delegation Agreement:

> (c) [REGIONAL ENTITY] shall report promptly to NERC information regarding noncompliance with a Reliability Standard, and its eventual disposition by [REGIONAL ENTITY], as set forth in, and subject to the confidentiality and disclosure provisions of, the NERC Rules of Procedure, the NERC Compliance Monitoring and Enforcement Program, this Agreement, compliance and enforcement program procedures and guidance that NERC may from time to time develop and the ERO Regulations. NERC shall promptly forward such report to the Commission, as required by the ERO Regulations, or as the Commission shall from time to time direct. NERC and [REGIONAL ENTITY] shall cooperate in filing such periodic summary reports and analyses as the Commission shall from time to time direct.

[59] *Id.* at 15. As discussed above, NERC also proposes to eliminate section 6(i), which requires NERC to review Regional Entity CMEP activities at least every five years.

> (d) All dispositions by [REGIONAL ENTITY] of noncompliance with Reliability Standards shall be reported to NERC for review. NERC shall develop and implement policies and procedures for the review and, where appropriate, approval of dispositions of noncompliance.[60]

2. Commission Determination

73. In proposed section 6(c), NERC includes the phrase, "compliance and enforcement program procedures and guidance that NERC may from time to time develop" in the list of resources for Regional Entities in reporting noncompliance with Reliability Standards and their eventual disposition. It is unclear whether NERC envisions developing procedures and guidance in addition to that contained in its Rules of Procedure, CMEP, and Delegation Agreements, all of which require filing with the Commission for approval. Nevertheless, we note that policies and procedures governing what information is reported to the Commission regarding noncompliance and when the information should be reported require Commission approval before they become effective. Thus, we direct NERC to clarify in its compliance filing, to be filed within 120 days of the date of this order, the meaning of other "guidance that NERC may from time to time develop," and that its guidance on reporting to the Commission instances of noncompliance of Reliability Standards and their disposition must be filed with the Commission for approval before it becomes effective.

F. Confidentiality (Section 15)

1. NERC Filing

74. NERC proposes to include new section 15(c) and to revise current section 15(d) in section 15 (Confidentiality) of the *Pro Forma* Delegation Agreements as follows:

> (c) The Parties may transfer or exchange such Confidential Information with and between the other Regional Entities as third-party beneficiaries of the terms of this Agreement, provided the Parties and the other Regional Entities as third-party beneficiaries continue to maintain the confidentiality of such information.

[60] NERC Petition, Attachment 2 Redline – Revised *Pro Forma* Regional Delegation Agreement, Section 6(c)–(d).

> (d) Except as set forth herein and within the NERC Rules of Procedure, the Parties agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the issuing Party or specified third-party beneficiary of this Agreement, unless disclosure is required by subpoena, law, or other directive of a court, administrative agency, or arbitration panel, in which event the recipient hereby agrees to provide the Party or specified third-party beneficiary of this Agreement that provided the Confidential Information with prompt notice of such request or requirement in order to enable such issuing Party or specified third-party beneficiary of this Agreement to (a) seek an appropriate protective order or other remedy, (b) consult with the recipient 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. In the event a protective order or other remedy is not obtained or the issuing Party or specified third-party beneficiary of this Agreement waives compliance with the provisions, the recipient agrees to furnish only that portion of the Confidential Information which the recipient's counsel advises is legally required and to exercise best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.[61]

75. NERC states that the revisions are intended to clarify the variety of confidential information shared among the business units of the ERO enterprise in exercising their delegated authority, as well as the handling of such information within the ERO enterprise.[62] NERC also states the revisions eliminate the need for ERO business units to draft *ad hoc* non-disclosure agreements as part of the ERO enterprise's daily activities. NERC states that the scope of confidential information under the Delegation Agreements

[61] NERC Petition, Attachment 2 Redline – Revised *Pro Forma* Regional Delegation Agreement, Section 15(c)–(d).

[62] NERC Petition at 21.

extends beyond the categories identified in section 1501 of the NERC Rules of Procedure.[63]

2. Commission Determination

76. We are concerned that the revisions to section 15 of the Delegation Agreements may impose an unreasonable condition on the Commission's ability to access confidential information necessary for effective regulation of the ERO and Regional Entities. As proposed, section 15 of the Delegation Agreements sets forth the provisions for sharing confidential information between NERC and the counterparty Regional Entity, as well as "specified third-party beneficiaries." Section 15(d) also requires the directed party to obtain written permission for disclosure from, or provide "prompt notice" to, the entity that issued the confidential information or a specified third-party beneficiary. Although NERC states that section 15 relates to the handling of confidential information within the ERO enterprise, section 15(d) may apply to disclosure of information sought by the Commission, as an "administrative agency," or its staff. The Delegation Agreements do not appear to contemplate the possibility that the Commission or a court may direct NERC or a Regional Entity not to notify any other entity of the required disclosure. This omission appears to conflict with section 1505.1 of the NERC Rules of Procedure, which provides:

> *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

[63] *Id.* at 21-22 & n.51 (NERC states that NERC Rules of Procedure section 1501 deals with Confidential Business and Market Information, Critical Energy Infrastructure Information, personal information, work papers, investigative files, including any records produced for or created in the course of an investigation, or Cyber Security Incident Information).

> Authorities that the Submitting Entity has marked the information as confidential.[64]

77. We are concerned that the apparent inconsistency between the proposed section 15(d) of the revised Delegation Agreements and section 1500 of the NERC Rules of Procedure may create unnecessary confusion. We believe that section 1500 of the NERC Rules of Procedure is clear and that proposed section 15(d) of the revised Delegation Agreement should not alter any obligations imposed by section 1500 of the NERC Rules of Procedure.

78. Proposed section 15(f) of the Delegation Agreements also refers to the NERC Rules of Procedure, but does not support the Commission's use of NERC Rules of Procedure section 1505.1 directives. Proposed section 15(f) states: "This confidentiality provision does not prohibit reporting and disclosure as directed by NERC, as set forth in Section 6 of this Agreement, nor does it prohibit permitted disclosures as set forth in the NERC Rules of Procedure." The "permitted disclosures" set forth in NERC Rules of Procedure section 1505 include disclosures to the Commission by NERC of information it receives from a Regional Entity and by NERC or a Regional Entity of information received from a Regional Entity or a user, owner or operator of the Bulk-Power System. While stating that the confidentiality provisions of the Delegation Agreement does not "prohibit" these disclosures, sections 15(d) and 15(f) together could permit NERC or an Regional Entity to *condition* such disclosures by disabling the authority of the Commission to issue a NERC Rules of Procedure section 1505.1 directive.

79. Thus, we direct NERC to submit a compliance filing within 120 days of the date of this order to include language in section 15 of the Delegation Agreements stating that the provisions of section 1500 of the NERC Rules of Procedure control when a conflict between it and the Delegation Agreements may arise.

The Commission orders:

(A) NERC's revised *Pro Forma* Delegation Agreement and revised Delegation Agreements with the eight Regional Entities are hereby conditionally approved, as discussed in the body of this order.

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[64] Section 1505.1 of the NERC Rules of Procedure (emphasis added). We also note that because NERC states that the phrase "Confidential Information" used in section 15 of the Delegation Agreements is broader than the definition of the same term in section 1501.1 of the Rules of Procedure, NERC or a Regional Entity could seek to condition its provision of broader categories of information to the Commission under section 15 than contemplated under the Rules of Procedure.

(B) NERC is hereby directed to submit a compliance filing within 120 days of the date of this order to revise the *Pro Forma* Delegation Agreement, as discussed in the body of this order.

(C) NERC shall include in its compliance filing, to be submitted within 120 days of the date of this order, revised individual Delegation Agreements with each Regional Entity reflecting the changes to the *Pro Forma* Delegation Agreement directed herein.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

November 12, 2015

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 19, 2015 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://www.ferc.gov using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1021ST - MEETING

REGULAR MEETING

November 19, 2015

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	AD07-13-009	2015 Report on Enforcement
A-4	AD16-12-000	Energy Storage Panel
		ELECTRIC
E-1	RM15-2-000	Third-Party Provision of Primary Frequency Response Service
E-2	AD14-14-000	Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators
E-3	RM16-1-000	Reactive Power Requirements for Non-Synchronous Generation
E-4	ER15-861-004	California Independent System Operator Corporation
E-5	ER15-2281-000 ER15-2282-001 ER15-2283-000	Nevada Power Company Sierra Pacific Power Company PacifiCorp
E-6	OMITTED	
E-7	RM15-3-001	Revisions to Public Utility Filing Requirements
E-8	RM11-12-001	Availability of E-Tag Information to Commission Staff
E-9	RM15-7-000	Revisions to Emergency Operations Reliability Standards
	RM15-12-000	Revisions to Undervoltage Load Shedding Reliability Standards

	RM15-13-000	Revisions to the Definition of “Remedial Action Scheme” and Related Reliability Standards
E-10	RM15-16-000	Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards
E-11	ER11-4081-001	Midwest Independent Transmission System Operator, Inc.
E-12	ER11-4081-002	Midwest Independent Transmission System Operator, Inc.
E-13	ER15-698-000 ER15-698-001	Northern States Power Company, a Minnesota corporation Northern States Power Company, a Wisconsin corporation
E-14	ER15-2292-000	Idaho Power Company
E-15	ER12-2399-003	PJM Interconnection, L.L.C. and American Transmission Systems, Inc.
E-16	OMITTED	
E-17	ER15-2260-001 EL14-24-000	PJM Interconnection, L.L.C.
E-18	EL14-26-000	New York Independent System Operator, Inc.
E-19	EL14-23-000	ISO New England Inc.
E-20	ER15-2295-000	Southwest Power Pool, Inc.
E-21	OMITTED	
E-22	ER15-572-003	New York Transco, LLC
E-23	ER15-2550-000	Rancho Cucamonga Municipal Utility
E-24	ER15-2588-000	Eastside Power Authority
E-25	ER12-39-000 ER12-39-001 EL13-63-000 EL13-63-001 EL14-90-000 ER13-1356-000 ER13-1356-001 ER14-1832-000 ER15-1618-000	Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency v. Florida Power Corporation Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency v. Duke Energy Florida, Inc. Duke Energy Florida, Inc.

E-26	EL08-14-010	Black Oak Energy, L.L.C., EPIC Merchant Energy, L.P. and SESCO Enterprises, L.L.C. v. PJM Interconnection, L.L.C.
E-27	ER12-1384-001 ER12-1385-002 ER12-1386-001 ER12-1387-001 ER12-1388-001 ER12-1390-001 EL11-57-002 (Consolidated)	Entergy Arkansas, Inc. Entergy Gulf States Louisiana, L.L.C. Entergy Louisiana, LLC Entergy Mississippi, Inc. Entergy New Orleans, Inc. Entergy Texas, Inc. Louisiana Public Service Commission v. Entergy Corporation, Entergy Services, Inc., Entergy Louisiana, LLC, Entergy Arkansas, Inc., Entergy Mississippi, Inc., Entergy New Orleans, Inc., Entergy Gulf States Louisiana, LLC, and Entergy Texas, Inc.
E-28	ER10-2001-004	Entergy Services, Inc.
E-29	ER10-2156-004	Consumers Energy Company
E-30	ER12-1653-005	New York Independent System Operator, Inc.
E-31	ER15-2272-000	California Independent System Operator Corporation
E-32	ER14-2017-001	California Independent System Operator Corporation
E-33	EL15-83-000	Joint Consumer Representatives v. PJM Interconnection, L.L.C.
E-34	EL10-55-002	Louisiana Public Service Commission v. Entergy Corporation, Entergy Services, Inc., Entergy Louisiana, L.L.C., Entergy Arkansas, Inc., Entergy New Orleans, Inc., Entergy Mississippi, Inc., Entergy Gulf States Louisiana, LLC, and Entergy Texas, Inc.
E-35	EL15-32-001	North Carolina Waste Awareness and Reduction Network, Inc. v. Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.
E-36	EL15-47-001	NextEra Desert Center Blythe, LLC v. California Independent System Operator Corporation
E-37	EL10-86-004	Jeffers South, LLC v. Midwest Independent Transmission System Operator, Inc.
E-38	EL12-98-001 EL12-98-002	Hudson Transmission Partners, LLC v. New York Independent System Operator, Inc.
E-39	EL15-25-001	New England Power Generators Association, Inc. v. ISO New England Inc.

E-40	EL15-62-000	Chevron U.S.A Inc.
E-41	EF15-8-000	Western Area Power Administration
E-42	OMITTED	
E-43	TS15-1-000	City of Alexandria, Louisiana
E-44	ER05-1056-009	Chehalis Power Generating, L.P.
E-45	ER14-1050-002 EL14-52-001	ISO New England Inc. and New England Power Pool
E-46	ER14-2419-003 EL14-52-002	ISO New England Inc.
E-47	ER15-2623-000 ER15-2625-000	Nevada Power Company

GAS

G-1	RP15-1022-001	Alliance Pipeline L.P.
G-2	IS14-607-000 IS14-608-000 IS14-609-000 IS14-610-000	Zydeco Pipeline Company LLC
G-3	IS09-348-004 IS09-395-004 IS10-204-002 IS10-491-000 IS09-348-006 IS09-395-006 IS10-204-004 IS10-491-003	BP Pipelines (Alaska) Inc.
	IS09-384-004 IS10-205-003 IS10-476-001 IS09-384-006 IS10-205-005 IS10-476-003	ConocoPhillips Transportation Alaska Inc.
	IS09-391-004 IS09-177-005 IS10-200-002 IS10-547-000 IS09-391-006 IS09-177-007 IS10-200-004 IS10-547-002	ExxonMobil Pipeline Company
	IS09-176-004 IS07-41-005 IS08-53-005 IS10-52-001	Unocal Pipeline Company

	OR10-3-001	
	IS10-490-000	
	IS11-3-000	
	IS09-176-006	
	IS07-41-007	
	IS08-53-007	
	IS10-52-003	
	OR10-3-004	
	IS10-490-002	
	IS11-3-002	
	IS10-54-001	Koch Alaska Pipeline Company, L.L.C.
	IS10-496-000	
	IS10-54-003	
	IS10-496-003	
G-4	OR15-53-000	Enterprise TE Products Pipeline Company LLC
G-5	TS13-3-001	KPC Pipeline, LLC

HYDRO

H-1	P-13351-021	Marseilles Land and Water Company
H-2	P-6142-008	Kevin Drone
H-3	P-2106-068	Pacific Gas and Electric Company
H-4	P-5-101	Confederated Salish and Kootenai Tribes Energy Keepers, Incorporated
H-5	P-2280-020	Seneca Generation, LLC
H-6	P-14628-006	Minneapolis Leased Housing Associates IV, Limited Partnership
H-7	HB81-09-2-003	Hudson River-Black River Regulating District
	P-12252-033	
	P-13-032	Green Island Power Authority and Albany Engineering Corp.
	P-2047-059	Erie Boulevard Hydropower L.P.
	P-2318-052	
	P-2482-099	
	P-2554-072	
	P-2385-028	FH Opco LLC
	P-2609-045	Curtis/Palmer Hydroelectric Co.
	P-2934-027	New York State Electric & Gas Corp.
	P-4226-006	Fort Miller Associates
	P-4684-069	GR Catalyst One., LLC
	P-5276-063	Northern Electric Power Co. and Niagara Mohawk Power Corp.
	P-5461-050	South Glens Falls Limited Partnership and Niagara Mohawk Power Corp.
	P-6032-074	Albany Engineering Corp.
H-8	P-1025-086	Safe Harbor Water Power Corporation

CERTIFICATES

C-1	OMITTED	
C-2	CP11-161-002	Tennessee Gas Pipeline, L.L.C.
C-3	CP15-100-000	National Fuel Gas Supply Corporation and National Fuel Gas Supply, LLC
C-4	CP14-555-000	Dominion Transmission, Inc.
C-5	CP14-513-001	Impulsora Pipeline, LLC

Nathaniel J. Davis, Sr.,
Deputy Secretary.

A free webcast of this event is available through www.ferc.gov. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit www.CapitolConnection.org or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

November 2015
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its November 19, 2015 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.

E-1 and E-3 – Press Release

E-2 – Press Release

FERC accepts a compliance filing

E-4, *California Independent System Operator Corporation*, Docket No. ER15-861-004. This order accepts CAISO's August 28, 2015 compliance filing proposing revisions to its tariff to specify readiness requirements and criteria that will apply to all prospective Energy Imbalance Market (EIM) Entities. The order accepts a series of readiness criteria a prospective EIM Entity must meet before CAISO and the prospective EIM Entity can certify the entity's readiness to begin financially binding EIM participation. The order also accepts CAISO's proposal to use pre-established thresholds to measure satisfaction of the readiness criteria, as well as CAISO's proposed process for granting exceptions to the thresholds and resolution to the exception before initiation of financially-binding operations.

FERC conditionally accepts in part market-based rate tariff provisions

E-5, *Nevada Power Company*, Docket No. ER15-2281-000, *et al.* This order accepts in part, subject to conditions, and rejects in part Nevada Power Company's and Sierra Pacific Power Company's (collectively, NV Energy), and PacifiCorp's (together with NV Energy, Berkshire EIM Sellers) market-based rate tariff revisions that reflect their participation in the Energy Imbalance Market (EIM) administered by the California Independent System Operator Corporation (CAISO), as expanded to include NV Energy. The order finds that the Berkshire EIM Sellers' market power analyses are deficient and fail to demonstrate a lack of market power in the expanded EIM. The order also outlines concerns regarding the ability of CAISO local market power mitigation to mitigate the Berkshire EIM Sellers' market power in the expanded EIM and therefore imposes the

following two conditions on the Berkshire's EIM Sellers' participation in the EIM at market-based rates: (1) the Berkshire EIM Sellers offer their units that are participating in the EIM into the EIM at or below each unit's Default Energy Bid, and (2) the Berkshire EIM Sellers facilitate CAISO's enforcement of all internal transmission constraints in the PacifiCorp and NV Energy balancing authority areas.

FERC grants clarification request

E-7, *Revisions to Public Utility Filing Requirements*, Docket No. RM15-3-001. This order grants a request for clarification filed by Dominion Resources Services, Inc. of a final rule that revised certain aspects of the Commission's regulations regarding FERC Form No. 566 - Annual Report of a Utility's 20 Largest Customers. The clarification explains that an entity that is both an exempt wholesale generator (EWG) and a qualifying facility is exempt from the filing requirement because, as an EWG, it qualifies for exemption.

FERC denies rehearing

E-8, *Availability of E-Tag Information to Commission Staff, Order No. 771-B*, Docket No. RM11-12-001. The order denies rehearing of Order No. 771 with respect to access to e-Tag data for the Commission and for Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), and Market Monitoring Units (MMUs). This order also clarifies (1) the responsibilities of Balancing Authorities under the Rule, (2) the scope of the access to e-Tags to be provided to RTOs, ISOs, and MMUs, (3) the confidentiality agreements that can be demanded of RTOs, ISOs, and MMUs before they are afforded access to e-Tags, (4) whether the access to e-Tags extended to RTOs, ISOs and MMUs should also be extended to Balancing Authorities, and (5) what is encompassed in a "complete e-Tag."

FERC approves revised reliability standards

E-9, *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. This final rule approves revisions to Reliability Standards EOP-011-1 and PRC-010-1, submitted by the North American Electric Reliability Corporation (NERC). The order also approves a revised definition of the term "Remedial Action Scheme" set forth in the NERC Glossary of Terms Used in Reliability Standards, and modifications of specified Reliability Standards to incorporate the revised definition.

FERC approves reliability standards

E-10, *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Docket No. RM15-16-000. This final rule approves revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards, developed by the North American Electric Reliability Corporation. The final rule also directs NERC to make three modifications to the standards within 18 months of the effective date of the final rule.

FERC denies rehearing, grants clarification

E-11, *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER11-4081-001. This order denies rehearing and grants clarification, in part, of the Commission's June 11, 2012 order on MISO's resource adequacy proposal.

FERC conditionally accepts proposed tariff revisions

E-12, *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER11-4081-002. This order accepts, subject to condition, MISO's proposed revisions to its resource adequacy construct in compliance with the Commission's June 11, 2012 order in this proceeding.

FERC accepts a filing

E-13, *Northern States Power Company, a Minnesota Company*, Docket No. ER15-698-000, *et al*. The order accepts revisions to the Interchange Agreement to insert an allocation method for NSP Companies to share the costs incurred by NSP Minnesota associated with the cancelled Prairie Island Extended Power Uprate related to the Prairie Island Project.

FERC denies a filing

E-14, *Idaho Power Company*, Docket No. ER15-2292-000. The order denies Idaho Power's request to verify that the demand inputs to its transmission formula rate may, upon closing of a transaction with PacifiCorp, reflect (1) the cancellation of 1,836 megawatts (MW) of terminated Legacy Agreements with PacifiCorp, and (2) the addition of 310 MW of demand associated with Long-Term Firm Point-To-Point Transmission Service reservations with PacifiCorp that replace the cancelled Legacy Agreements. In addition, the order also denies Idaho Power's alternative request, in the event the Commission finds that Idaho Power does not have existing authority under its transmission formula rate to reflect upon closing the cancellation of the Legacy Agreements or the Long-Term Firm Point-To-Point Transmission Service, to (1)

authorize Idaho Power to make a one-time adjustment of the inputs to the demand portion of its formula rate to reflect the cancellation of the Legacy Agreements and/or the addition of the Long-Term Firm Point-To-Point Transmission Service, and (2) grant a limited, one-time waiver of several provisions within its formula rate necessary to effect any the adjustment.

FERC affirms an Initial Decision

E-15, *PJM Interconnection, L.L.C. and American Transmission Systems, Inc.*, Docket No. ER12-2399-000 and 003. This order affirms an Initial Decision's determination that proposed revisions to Attachments M-1 and M-2 of PJM's Open Access Transmission Tariff should apply to Old Dominion Electric Cooperative (ODEC) and certain ODEC load, and thus that FirstEnergy Service Company – and not ODEC – is responsible for calculating and reporting to PJM certain ODEC load data.

FERC accepts proposed tariff records

E-17, *PJM Interconnection, L.L.C.*, Docket Nos. ER15-2260-001 and EL14-24-000. On March 20, 2014, the Commission instituted an inquiry in accordance with section 206 of the Federal Power Act (FPA) to ensure that PJM's scheduling, particularly its day-ahead scheduling practices, correlate with revisions to the natural gas scheduling practices ultimately adopted by the Commission in Order No. 809. On July 23, 2015, as amended on August 7, 2015, PJM proposed revisions, under section 205 of the FPA, to the PJM Open Access Transmission Tariff and Amended and Restated Operating Agreement. This order accepts PJM's proposed tariff revisions, as better aligning PJM's scheduling with that of the natural gas industry.

FERC accepts proposed compliance filing

E-18, *New York Independent System Operator, Inc.*, Docket No. EL14-26-000. On March 20, 2014, the Commission instituted an inquiry in accordance with section 206 of the Federal Power Act (FPA) to ensure NYISO's scheduling, particularly its day-ahead scheduling practices, correlate with revisions to the natural gas scheduling practices ultimately adopted by the Commission in Order No. 809. On July 23, 2015, NYISO submitted a compliance filing, contending that its existing day-ahead scheduling practices need not be changed. The order finds that NYISO has justified retaining its existing scheduling practices unchanged.

FERC accepts a compliance filing

E-19, *ISO New England, Inc.*, Docket No. EL14-23-000. In a prior order, the Commission instituted an inquiry in accordance with section 206 of the Federal Power Act to ensure that ISO-NE's scheduling, particularly its day-ahead scheduling practices,

correlated with revisions to the natural gas scheduling practices later adopted by the Commission in Order No. 809. On July 23, 2015, ISO-NE submitted a compliance filing, contending that its existing day-ahead scheduling practices need not be changed. The order finds that ISO-NE has justified retaining its existing scheduling practices unchanged.

FERC grants a tariff waiver

E-20, *Southwest Power Pool, Inc.*, Docket No. ER15-2295-000. The order grants SPP's request for a tariff waiver that would allow it to resettle past invoices that, due to computer software issues, could not all be corrected and resettled within one year as required by its tariff.

FERC grants request for a temporary and limited tariff waiver

E-22, *New York Transco, L.L.C.***,** Docket No. ER15-572-003. This order grants New York Transco, L.LC.'s request for a temporary and limited waiver of its transmission formula rate implementation protocols in NYISO's Open Access Transmission Tariff, which require New York Transco to post its Net Adjusted Revenue Requirement (NARR) by September 30, 2015. The order explains that the NARR includes certain inputs that the Commission has set for hearing and settlement judge procedures, and therefore are not available at this time. The order finds good cause in this circumstance to grant the waiver.

FERC denies request for a waiver

E-23, *Rancho Cucamonga Municipal Utility*, Docket No. ER15-2550-000. The order denies Rancho Cucamonga Municipal Utility's (RCMU) request for waiver of the tariff requirement of the California Independent System Operator Corporation (CAISO) to timely file monthly Resource Adequacy plans and of the associated penalty provisions. The order finds that, based on the criteria for waiver, RCMU fails to demonstrate that its failure to timely submit Resource Adequacy plans to CAISO warrants relief from the sanctions imposed.

FERC denies request for a waiver

E-24, *Eastside Power Authority*, Docket No. ER15-2588-000. The order denies Eastside Power Authority's request for waiver of the tariff requirement of the California Independent System Operator Corporation (CAISO) to timely file monthly Resource Adequacy plans and of the associated penalty provisions. The order finds that, based on the criteria for waiver, Eastside fails to demonstrate that its failure to timely submit Resource Adequacy plans to CAISO warrants relief from the sanctions imposed.

FERC approves an uncontested settlement

E-25, *Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency v. Duke Energy Florida, Inc.*, Docket Nos. EL12-39-000, *et al*. This letter order approves an uncontested settlement agreement establishing the rate of return on equity in Duke Energy Florida's formula rate under Duke Energy Carolinas L.L.C.'s Joint Open Access Transmission Tariff.

FERC approves an order on remand

E-26, *Black Oak Energy, L.L.C., EPIC Merchant Energy, L.P. and SESCO Enterprises, L.L.C. v. PJM Interconnection, L.L.C.*, Docket No. EL08-14-010**.** In an opinion issued on August 6, 2013, the United States Court of Appeals for the District of Columbia Circuit remanded to the Commission for further consideration the issue of whether PJM may require the Financial Marketers to repay refunds after the Commission determined on rehearing that its earlier order directing refunds was contrary to Commission policy. In balancing these interests, the Commission has determined in this order that Financial Marketers should be required to repay refunds, with interest, to put the parties back in the positions in which they would have found themselves if the Commission had not erred in requiring refunds in the first place.

FERC affirms in part and reverses in part an Initial Decision

E-27, *Entergy Services, Inc*., Docket No. ER12-1384-001, *et al*. The order affirms in part and reverses in part an Initial Decision addressing Entergy's proposal to include costs associated with the cancellation of the Little Gypsy Repowering Project in Service Schedule MSS-3 of the Entergy System Agreement.

FERC denies rehearing

E-28, *Entergy Services, Inc*., Docket No. ER10-2001-004, *et al*. The order denies rehearing of Opinion No. 523 concerning Entergy Arkansas, Inc.'s proposed depreciation rates, which use depreciation cost inputs that were approved by retail regulators, in its

FERC affirms in part and reverses in part an Initial Decision

E-29, *Consumers Energy Co*., Docket No. ER10-2156-002 and 004. The order affirms in part and reverses in part the Initial Decision in this proceeding concerning time value refunds on a late-filed interconnection agreement between Consumers Energy and Midland Cogeneration Venture Limited Partnership, (Midland). The order holds, consistent with recent Commission precedent, that no time value refunds are required in this case because their imposition would cause the service provider to operate at a loss, contrary to Commission policy; the amounts collected under the interconnection

agreement simply reimbursed actual costs and included no profit or return. The order also requires Midland to reimburse, with interest, all unpaid actual costs for the interconnection service it received.

FERC accepts a filing

E-30, *New York Independent System Operator, Inc.*, Docket No. ER12-1653-005. The order accepts NYISO's August 2014 filing to comply with the Commission's prior order that conditionally accepted NYISO's proposals to establish a revised compensation methodology governing the provision of frequency regulation service, as required by Order No. 755.

FERC grants authorization

E-31, *California Independent System Operator Corporation*, Docket No. ER15-2272-000. This order grants CAISO's request for authorization to include in the local market power mitigation procedures under section 29.39(d)(2) of the CAISO tariff Energy Imbalance Market transfer constraints between the NV Energy balancing authority area and the CAISO and PacifiCorp East balancing authority areas.

FERC accepts a filing

E-32, *California Independent System Operator Corporation*, Docket No. ER14-2017-001. The order accepts the CAISO's September 2, 2014 compliance filing that includes an accuracy metric to evaluate the effectiveness of CAISO's enhancing its Full Network Model to include modeling in CAISO's day-ahead market unscheduled flows and enforcing physical flow limits on its interties.

FERC denies a complaint

E-33, *Joint Consumer Representatives v. PJM Interconnection, L.L.C.*, Docket No. EL15-83-000. This order denies a complaint by Joint Consumers requesting that the Commission direct PJM to update its existing 2015 PJM Region Peak Load Forecast values for purposes of certain capacity auctions, so as to reflect the impact of recent enhancements to PJM's load forecasting model. The order explains that Joint Consumers have failed to show that PJM's compliance with its existing Open Access Transmission Tariff provisions was unjust and unreasonable, or that the tariff itself is unjust and unreasonable.

FERC denies rehearing

E-34, *Louisiana Public Service Commission v. Entergy Services, Inc.*, Docket EL10-55-002. This order denies rehearing of Opinion No. 519, which denied a complaint by the

Louisiana Public Service Commission arguing that FERC may not use state-determined depreciation inputs in the bandwidth formula used to equalize production costs among the Entergy operating companies. The order reaffirms the Commission's finding that the Louisiana Commission has not shown that it is unjust, unreasonable or unduly discriminatory or preferential for the Commission to use state-determined depreciation rates in the bandwith formula.

FERC denies rehearing

E-35, *North Carolina Waste Awareness, Inc. v. Duke Energy Carolinas, L.L.C .and Duke Energy Progress, Inc.*, Docket No. EL15-32-001. The order denies the request for rehearing filed by the North Carolina Waste Awareness and Reduction Network, Inc. (NC WARN) concerning the Commission's April 15, 2015 order denying NC WARN's complaint against Duke Energy Carolinas, LLC and Duke Energy Progress, Inc. (together, Duke Energy). The Commission reaffirms its decision not to investigate further the claims NC WARN raised in its complaint: whether Duke Energy's capacity construction and procurement-related activities resulted in unjust and unreasonable wholesale energy or transmission rates; whether Duke Energy engaged in market manipulation; and whether Duke Energy failed to comply with Order No. 1000 and related orders and policies.

FERC denies rehearing

E-36, *NextEra Desert Center Blythe, L.L.C. v. California Independent System Operator Corporation*, Docket No. EL15-47-001. This order denies NextEra's request for rehearing of the Commission order denying NextEra's complaint against CAISO. The order affirms the Commission's finding that NextEra has not demonstrated that it is entitled to the allocation of Congestion Revenue Rights created by its investment in the Interim West of Devers upgrades.

FERC denies rehearing

E-37, *Jeffers South, LLC v. Midcontinent Independent System Operator, Inc.*, Docket No. EL10-86-004. This order denies MISO's request for rehearing of the Commission's July 18, 2013 order that reversed an April 16, 2012 Initial Decision in this proceeding. In its July 2013 order, the Commission found that MISO had violated its obligations regarding the study of network upgrades that are required to accommodate the interconnection of the Jeffers South generation facility (Jeffers South Project) when MISO concluded that Jeffers South was obligated to fund construction of a facility referenced as the Dotson-New Ulm. The order provides guidance regarding the appropriate steps to be taken in processing the Jeffers South Project interconnection request.

FERC denies rehearing

E-38, *Hudson Transmission Partners, L.L.C. v. New York Independent System Operator, Inc.* Docket Nos. EL12-98-001 and 002. This order denies Hudson Transmission Partners' (HTP) request for rehearing of the Commission's November 2013 Order that granted in part, and denied in part, HTP's complaint alleging that NYISO improperly implemented its buyer-side market power mitigation exemption test with respect to HTP's merchant transmission facility. The order grants clarification regarding the extent a holder of unused unforced deliverability rights (UDRs) has the ability to retain or sell those rights. The order also finds that NYISO satisfactorily fulfilled its compliance requirements to provide the specific scaling factor used for the HTP Project, to explain in detail how it was calculated, and to support the methodology. The order concludes that the specific methodology used for the HTP Project could not practically be applied to other UDR projects and directs NYISO to file, within 90 days, a further compliance filing containing tariff provisions that provide the conceptual basis and framework for a scaling factor and that are sufficiently broad and flexible to allow for the kinds of variations that exist with respect to UDR projects.

FERC denies rehearing

E-39, *New England Power Generators Association, Inc. v. ISO New England, Inc.*, Docket No. EL15-25-001. This order denies rehearing of an earlier order denying a complaint filed by New England Power Generators Association (NEPGA). NEPGA alleged that the interaction between ISO-NE's Peak Energy Rent mechanism (which requires suppliers to make rebates to customers when energy prices exceed a strike price) and new increased Reserve Constraint Penalty Factors (a rate used within the real-time dispatch and pricing algorithm, which serves as a cap on the price that ISO-NE may pay to procure additional reserves) had rendered ISO-NE's tariff unjust and unreasonable. The Commission found in its earlier order denying the complaint that NEPGA had not met its burden under Federal Power Act section 206 of demonstrating that the existing tariff provisions were unjust and unreasonable. This rehearing order reaffirms that finding.

FERC grants a request for declaratory order

E-40, *Chevron U.S.A., Inc.*, Docket No. EL 15-62-000. This order grants Chevron's petition for declaratory order, finding that, under section 210 of the Public Utility Regulatory Policies Act of 1978 and section 292.601(c) of the Commission's regulations, Chevron's affiliates that are qualifying facilities with market-based rate authorization and/or generation interconnection facilities are exempt from section 203(a)(1) of the Federal Power Act.

FERC approves a waiver request

E-41, *Western Area Power Administration*, Docket No. TS15-1-000. On July 23, 2015, the Deputy Secretary of the United States Department of Energy filed a request for final confirmation and approval of the proposed formula transmission and ancillary service rate schedules for Western Area Power Administration's (Western) Pick-Sloan Missouri Basin Program--Eastern Division. The order confirms and approves on a final basis Western's transmission and ancillary service rates for WUAGP-ATRR for Annual Transmission Revenue Requirement, WAUGP-AS1 for Scheduling, System Control, and Dispatch Service, WAUW-AS3 for Regulation and Frequency Response Service, WAUW-AS4 for Energy Imbalance Service, WAUW-AS5 for Operating Reserve-Spinning Service, WAUW-AS6 for Operating Reserve-Supplemental Service, and WAUW-AS7 for Generator Imbalance Service. The order also approves Western's request for waiver of the Commission's requirements set forth in FERC's regulations to file Statements A through F, a Power Repayment Study, and a Cost of Service Study, respectively.

FERC grants request for waiver of tariff provisions

E-43, *City of Alexandria, Louisiana*, Docket No. TS15-1-000. The order grants a request by the City of Alexandria for waiver of the requirements to file an Open Access Transmission Tariff, to establish and maintain an Open Access Same Time Information System, and to comply with the Commission's Standards of Conduct.

FERC denies rehearing

E-44, *Chehalis Power Generating, L.P.*, Docket No. ER05-1056-009. This order denies Chehalis' request for rehearing of the Commission's finding that the Commission lacks the authority to order Bonneville Power Administration to return refunds that Chehalis had previously paid to Bonneville.

FERC denies rehearing

E-45, *ISO New England Inc.*, Docket No. ER14-1050-002 and EL14-52-001. This order addresses and denies requests for rehearing of a Commission order that directed ISO-NE to adopt a modified version of ISO-NE's proposed performance-based capacity market design, and to increase the Reserve Constraint Penalty Factors in ISO-NE's energy and ancillary services markets.

FERC denies rehearing

E-46, *ISO New England Inc.*, Docket Nos. ER14-2419-003 and EL14-52-002**.** This order addresses and denies requests for rehearing of a Commission order that accepted in part,

subject to condition, and rejected in part ISO-NE's compliance filing to adopt a modified version of ISO-NE's proposed performance-based capacity market design, and to increase the Reserve Constraint Penalty Factors in ISO-NE's energy and ancillary services markets.

FERC rejects proposed agreements

E-47, *Nevada Power Company*, Docket Nos. ER15-2623-000 and ER15-2625-000. Nevada Power Company (Nevada Power) filed a proposed Operation and Maintenance Agreement (O&M Agreement) and a proposed License and Sale Agreement (L&S Agreement) between Nevada Power and DesertLink, LLC. Concurrently, Nevada Power and Sierra Pacific Power Company (Sierra Pacific) (jointly, NV Companies) filed a proposed amended and restated Transmission Use and Capacity Exchange Agreement (Amended TUA) among Nevada Power, Sierra Pacific, Great Basin Transmission South, L.L.C. and Great Basin Transmission, L.L.C. The order rejects the proposed O&M Agreement, L&S Agreement, and Amended TUA as premature, without prejudice to Nevada Power or NV Companies refiling the agreements at a later date.

FERC grants in part and denies in part revised tariff revisions

G-1, *Alliance Pipeline L.P.*, Docket No. RP15-1022-001. This order addresses requests for rehearing of the Commission's June 30, 2015 order that accepted and suspended Alliance's revised tariff records, subject to refund, and established a hearing. Alliance proposed to modify its service offerings and make other changes to its tariff. Parties sought either rehearing of the Commission's June 2015 order or expedited consideration of Alliance's proposal to eliminate Authorized Overflow Service (AOS) before the end of the suspension period, December 1, 2015. The order finds that, although Alliance may remove the scheduling priority for AOS service over other interruptible service, it may not remove AOS service entirely from its tariff in circumstances where the parties' negotiated rate agreements contemplate the availability of AOS. The order also disposes of various parties' other requests for rehearing and clarification related to the scope of the hearing and other issues.

FERC approves an offer of settlement

G-2, *Zydeco Pipeline Company LLC*, Docket No. IS14-607-000, *et al*. This order approves an offer of settlement submitted August 14, 2015 by Zydeco and its petroleum products shippers, Anadarko Petroleum Corporation, ConocoPhillips Company, and Pioneer Natural Resources USA, Inc. (Liquids Shippers Group). The settlement is uncontested and resolves all outstanding issues concerning the rates for transportation on Zydeco's system that transports petroleum between Houston, Texas, and Houma, Louisiana, known as the Ho-Ho System. The order finds the settlement to be fair and reasonable, and in the public interest.

FERC affirms an Initial Decision

G-3, *BP Pipelines (Alaska) Inc., et al.* Docket No. IS09-348-000, *et al.* This order addresses briefs on and opposing exceptions to an Administrative Law Judge's Initial Decision regarding rate filings on the Trans Alaska Pipeline System (TAPS). The order affirms the Initial Decision's finding that the costs of the TAPS Strategic Reconfiguration Project were imprudently incurred, and generally affirms the Initial Decision's remedy. The order also affirms the Initial Decision's holdings related to base/test period issues, ad valorem taxes, and oil-spill-related costs. The order also modifies the Initial Decision's holding related to litigation costs.

FERC grants request for a declaratory order

G-4, *Enterprise TE Products Pipeline Company LLC*, Docket No. OR15-35-000. The order grants Enterprise TE's petition for declaratory order seeking approval of the proposed rate structure and terms of service for an expansion of Enterprise TE's Aegis pipeline system, known as the Aegis Expansion Project. The Aegis pipeline is a 270-mile pipeline designed to transport purity ethane from Mont Belvieu, Texas, to Napoleonville, Louisiana, with various intermediate delivery points in Texas and Louisiana.

FERC denies rehearing

G-5, *KPC Pipeline, LLC*, Docket No. TS13-3-001. The order denies KPC Pipeline, LLC's request for rehearing of the Commission's April 7, 2014 order denying KPC's request for a partial waiver of the Commission's Standards of Conduct.

FERC grants a stay

H-1, *Marseilles Land and Water Company*, Project Number 13351-021. The order grants the licensee's request for a 60-day stay of Article 301 of its license, finding that for reasons beyond its control Marseilles L&W will not be able to timely commence project construction.

FERC terminates exemption implied by surrender of hydro license

H-2, *Kevin Drone*, Project No. 6142-008. The order terminates, by implied surrender, the exemption for the 240-kilowatt Dardanelles Creek Hydroelectric Project No. 6142, located on the Dardanelles and Pond Creeks in Placer County, California.

FERC denies rehearing

H-3, *Pacific Gas and Electric Company*, Project No. 2106-068. The order denies rehearing of Commission staff's August 3, 2015 letter dismissing Pacific Gas and

Electric Company's (PG&E) application to convey certain property rights at the McCloud-Pit Project No. 2106 on the McCloud and Pit Rivers in Shasta County, California, and finds that Commission staff properly dismissed the application as premature when PG&E sought the conveyance to carry out an as-yet ineffective mandatory Forest Service condition proposed in the project's pending relicensing proceeding.

FERC denies rehearing

H-4, *Confederated Salish & Kootenai Tribes of the Flathead Reservation and Energy Keepers, Inc.*, Project No. 5-101. The order denies the rehearing requests filed by Montana Land and Water Alliance, Montana Public Service Commission, and Senators Verdell Jackson and Bob Keenan of Commission staff's September 1, 2015 order approving a partial transfer of the license for the Séliš Ksanka QÍispé Project No. 5, located on the Flathead River in Flathead and Lake Counties, Montana. The order finds that the issues raised on rehearing largely relate to a self-executing conveyance established in the final 1985 license for the project, and are not germane to the partial transfer order, and the order affirms that the partial transfer to Energy Keepers, Incorporated is in the public interest.

FERC denies rehearing requests

H-5, *Seneca Generation, LLC,* Project No. 2280-020. The order denies two requests for rehearing of Commission staff's July 22, 2015 license order that authorized Seneca Generation, LLC to continue operation and maintenance of the Kinzua Pumped Storage Project No. 2280, located on the Allegheny River in Warren County, Pennsylvania. The order denies Seneca Generation's request to remove two Forest Service 4(e) conditions because the Commission has no authority to reject mandatory conditions as unreasonable, and the conditions are not contrary to the law. The order also denies the U.S. Department of the Interior's assertion that the Commission failed to fulfill its consultation obligations under section 7 of the Endangered Species Act by not addressing the snuffbox and sheepnose mussels in the Environmental Assessment or license order.

FERC grants rehearing

H-6, *Minneapolis Housing Associates IV, Limited Partnership,* Project No. 14628-006. The order grants rehearing of Commission staff's September 4, 2015 order issuing an original license to Minneapolis Housing Associates for the 600-kilowatt A-Mill Artist Lofts Hydroelectric Project No. 14628, to be located in Minneapolis, Minnesota. In doing so, the order amends the license to clarify that the A-Mill Project is only authorized to utilize flow from the St. Anthony Falls project reservoir "that is in excess of that required for operation and maintenance of the St. Anthony Falls Project" as a source of water for the A-Mill project and to prohibit Minneapolis Housing Associates from

construction activities or operation that may affect Xcel's ability to operate the St. Anthony Falls Project for generation and other project purposes.

FERC denies in part and grants in part request for rehearing

H-7, *Hudson River-Black River Regulating District, et al.,* Docket No. HB81-09-2-003, et al. The order denies in part and grants in part Erie Boulevard Hydropower L.P.'s request for rehearing of Commission staff's August 21, 2015 order calculating dates for commencement of headwater benefits assessments in the Hudson River Basin. The order also denies a request for rehearing filed by South Glens Falls Limited Partnership and Northern Electric Power Co., dismisses as moot stay requests, and grants clarification.

FERC grants rehearing

H-8, *Safe Harbor Water Power Corporation*, Project No. 1025-086. The order grants rehearing of Commission staff's March 16, 2015 order approving a proposal by Safe Harbor Water Power Corporation to increase the normal maximum water surface elevation of the project impoundment. In response to concerns about potential impacts of the elevation increase on migratory shorebirds during the April 15 to October 15 migration season, the order finds that there is not sufficient evidence to justify an increase in the water surface elevation from April 15 to October 15.

FERC responds to federal appeals court ruling

C-2, *Tennessee Gas Pipeline Company, L.L.C.*, Docket No. CP11-161-002. This order responds to the ruling of the U.S. Court of Appeals for the D.C. Circuit in *Delaware Riverkeeeper v. FERC* that found that the Commission violated the National Environmental Policy Act by: (1) segmenting its environmental review of the Tennessee's Northeast Upgrade Project from that of three other Tennessee pipeline projects on the Eastern Leg of the 300 Line; and (2) failing to provide a meaningful analysis of the cumulative impacts of the four projects to show that the impacts would be insignificant. Based on the supplemental environmental analysis developed in response to the court's mandate, the order concludes that, when considered additively, impacts from the Northeast Upgrade Project and Tennessee's three other projects are not significant. It also concludes that when the projects are considered cumulatively with the Northeast Upgrade Project, there are no significant cumulative impacts. The order adopts the findings in the supplemental analysis and finds that no additional mitigation is required for the Commission's authorization of Tennessee's Northeast Upgrade Project.

FERC authorizes abandonment of natural gas facilities

C-3, *National Fuel Gas Supply Corporation and National Fuel Gas Supply, L.L.C.*, Docket No. CP15-100-000. This order grants National Gas Fuel Supply Corp. (Supply

Corp) and National Fuel Gas Supply, LLC's (Supply LLC) joint application for Supply Corp. to abandon by transfer all of its jurisdictional facilities and services to Supply LLC, and for Supply LLC to acquire and operate Supply Corp.'s jurisdictional facilities and services. National Fuel seeks this authorization in order to facilitate a change of the legal ownership of National Fuel from a Pennsylvania corporation to a Delaware limited liability company.

FERC conditionally approves an interstate natural gas pipeline project

C-4, *Dominion Transmission, Inc.*, Docket No. CP14-555-000. The order grants Dominion's requested authorization to construct and operate pipeline, compression, regulation, valves, and other facilities in Ohio and Pennsylvania for its Lebanon West II Project, subject to conditions.

FERC denies rehearing

C-5, *Impulsora Pipeline, LLC,* Docket No. CP14-513-001. This order denies a request for rehearing filed by Needmore Dolores, LLC (Needmore) of the Commission's May 14, 2015 order granting Impulsora Pipeline's request for Natural Gas Act section 3 authorization and a Presidential Permit to construct border crossing facilities to transport gas from Texas to a proposed natural gas power plant in Nuevo Leon, Mexico. In its rehearing request, Needmore alleged the Commission erred by issuing the order before Impulsora had acquired the necessary property rights from Needmore, and that the Commission failed to take Needmore's preferences into account, or provide them with an opportunity to comment on FERC staff's Environmental Assessment (EA). Needmore also states that the EA for the project failed to consider the impacts from non-jurisdictional, intrastate pipelines and gathering facilities, and failed to consider adequate alternatives or include proper mitigation measures. The order rejects these arguments. The order also amends the May 14 Commission order and issues Impulsora an amended Presidential Permit, in order to correct the length of the pipeline subject to the jurisdiction of the Commission.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Loss of EMS Due to RTU LAN and UPS Failure

Primary Interest Groups
Balancing Authorities (BAs)
Reliability Coordinators (RCs)
Transmission Operators (TOPs)

Problem Statement
A temporary rack-mounted uninterruptible power supply (UPS) failed, resulting in the loss of the remote terminal unit (RTU) local area network (LAN), the loss of system visibility, and the failure of the inter-control center communications protocol (ICCP) link for 50 minutes.

Details
The entity went through a supervisory control and data acquisition (SCADA) and energy management system (EMS) hardware replacement a few years prior and needed to run two simultaneous SCADA/EMS systems during the transition. Since the system UPS was not large enough to handle the hardware associated with two complete SCADA/EMS systems, a rack-mounted UPS had been installed as a temporary solution. When the hardware replacement was complete, the entity decided not to restore the system to its original configuration by removing the temporary UPS, instead deciding to leave it in and use it as an additional layer of backup power.

The rack-mounted UPS failed due to end of life of the battery pack. This specific make/model did not have an internal bypass to allow it to fail over to house power upon any loss of UPS capability. The vendor's technical support indicated only specific models have the internal bypass feature. Therefore, the RTU LAN lost power and failed to communicate.

Due to ambient noise and the unmanned nature of the computer room, it is not known if the UPS attempted to warn of impending battery failure. A contributing factor to the duration of the outage was that the RTU LAN communications network at the backup site was in "listen-only mode," which is an abnormal SCADA/EMS system setup configuration that made the replacement more difficult. The front-end processor (FEP) for the RTU LAN at the backup site was switched to the replacement system, eliminating the ability to fail over EMS capability to the backup site during primary site restoration efforts.

At the time this event took place, the entity was in transition to a new SCADA/EMS system, including hardware and software, and the system UPS had already been upgraded. The new UPS was capable of handling all needed devices, so rack-mounted UPSs were not needed.

Corrective Actions

- The RTU LAN routers were plugged into another UPS and rebooted, restoring EMS visibility and ICCP link connectivity.
- The FEP at the remote site was reconfigured to allow sending data to both the replacement SCADA/EMS and the old SCADA/EMS systems simultaneously by using additional IP addresses.
- The primary and backup routers at the primary site were plugged into alternate UPSs.
- The temporary rack-mounted UPS will be removed upon cutover to the replacement SCADA/EMS system

Lessons Learned

- UPS systems should be checked to verify they have an internal bypass so that power is not interrupted in the event of UPS failure. This may require review of the technical specification or consultation with the manufacturer.
- Where a UPS does not have internal bypass capabilities, investigate the use of a stand-alone automatic transfer switch (ATS).
- Periodic maintenance and monitoring on any UPS system is beneficial. While some UPS systems perform battery maintenance/cycling internally, additional checks and testing may be needed to verify existing bypass capabilities, current loading, and other desired functionality.

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 – Lessons Learned (via email)
Source of Lesson Learned:	Florida Reliability Coordinating Council
Lesson Learned #:	20151001
Date Published:	October 20, 2015
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.

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

2015 NPCC Compliance Committee Meetings (as of 1/14/15)

January 14…conference call

February 18…conference call

March 17-18 (Tue, Weds) at NextEra, Juno Beach, FL

April 15…conference call

May 13…conference call

May 19-21 Compliance Workshop (Tue-Thurs) Newport, RI Marriott.
(Week before the Memorial Day holiday)

June 16-17 (Tues, Weds) at IESO, Toronto.

July 15…CC conference call

August 19…CC conference call

September 22, 23 (Tues, Weds)…at NPCC, NYC
(Rescheduled from 9/15-9/16 on the Jan 2015 CC Call)

October 14…CC conference call

November…no conference call

November 10-12 Compliance Workshop (Tue – Thurs) Westchester, NY
(Date moved from 11/17-11/19 in December 2014 due to GRIDEX III conflict)

December 3, 4 (Thus, Fri)…at Albany, NY Marriott– after NPCC annual meetings.

As of 1/14/15

Rui Da Shu

From: NERC Standards Announcements (Do Not Reply) <NERC-StandardsAnnouncements-DoNotReply@nerc.net>
Sent: Tuesday, September 29, 2015 9:07 AM
To: monica.benson@nerc.net
Subject: NERC Standards Announcement | 2016-2017 Standards Committee Term Elections
Attachments: SC_nomination_Form_2016-2017_092815_final.doc

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

TO: REGISTERED BALLOT BODY

STANDARDS

NERC ROSTER

Standards Committee Elections

SC Election 2016–2017 — Segments 1-10 (Two-year Terms)

Registered Ballot Body members and others interested in NERC Reliability Standards are encouraged to submit nominations for industry segment representatives on the Standards Committee (SC). Reliability Standards are mandatory for all bulk power system owners, operators, and users in North America, and the SC's oversight role is therefore increasingly important. The SC consists of two members from each of the ten Industry Segments that make up the Registered Ballot Body. In addition, Appendix 3B of the Rules of Procedure contains special provisions to be used to ensure Canadian representation if at least two of the twenty SC representatives are not Canadian.

The SC is elected by industry stakeholders and reports directly to the NERC Board of Trustees. The SC meets six to 12 times each year, either by conference call or in face-to-face meetings. SC members who cannot travel to the meetings may participate by conference call. The Standards Committee Charter provides a description of the SC's responsibilities.

Each of the ten Industry Segments has an open position a two-year term ending December 31, 2017. The following individuals have terms expiring the end of this year:

Segment	Representative	Title	Organization
1	Laura Lee	Manager of ERO Support and Event	Duke Energy

Transmission Owners		Analysis, System Operations	
2 *Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs)*	Ben Li	Consultant	Independent Electric System Operator
3 *Load-Serving Entities (LSEs)*	Ron Parsons	General Manager of Transmission Interconnections and Operations	Alabama Power Company
4 *Transmission Dependent Utilities (TDUs)*	Frank Gaffney	Assistant General Manager, Power Resources	Florida Municipal Power Authority
5 *Electric Generators*	Randy Crissman	Vice President, Technical Compliance	New York Power Authority
6 *Electricity Brokers, Aggregators, and Marketers*	Andrew Gallo	Director, Reliability Compliance	City of Austin dba Austin Energy
7 *Large Electricity End Users*	Frank McElvain	Senior Consulting Manager	Siemens Energy, Inc.
8 *Small Electricity Users*	Robert Blohm	Managing Director	Keen Resources Ltd.
9 *Federal, State, and Provincial Regulatory or other*	Jerry Maio	Public Utilities Engineer - Electrical	Utah Public Service Commission

Government Entities			
10 *Regional Entities*	Guy Zito	Assistant Vice President of Standards	Northeast Power Coordinating Council

Any Industry Segment that intends to use a special procedure to elect its SC representatives must provide a copy of its procedure and evidence that the procedure was ratified by at least two-thirds of the registered entities in that segment to Monica Benson at monica.benson@nerc.net by **October 5, 2015**.

Anyone may submit a nomination. However, the nominee must be from an entity registered in the particular segment for which the nomination is received. Instructions are provided in Appendix 3B of the NERC Rules of Procedure - Election of Members of the NERC Standards Committee Procedure. Completed nomination forms will be posted on the SC Nominations and Elections webpage. A blank nomination form is attached to this email.

Please submit completed SC nomination forms to monica.benson@nerc.net no later than **Monday, October 19, 2015**. An election of segment representatives will be conducted immediately after the nominations period is closed.

Sincerely,

Monica Benson

Reliability Standards Analyst

Questions may be addressed to monica.benson@nerc.net or by calling 404-446-2573.

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