



1040 Avenue of the Americas - 10th Floor
New York, New York 10018-3703

NPCC Regional Standards Committee
Preliminary Agenda
Meeting # 13-1

Feb. 20, 2013 10:00 a.m. - 5:00 p.m.
Feb. 21, 2013 8:00 a.m. - 3:00 p.m.

FRCC Offices
3000 Bayport Drive
Suite 690
Tampa, FL 33607

Tel: 813-289-5644

Dress Business Casual

RSC@npcc.org

Call in 719-785-1707, Guest Code 8287#

Note: For reference. [Glossary of Terms Used in NERC Reliability Standards](#) dated Jan. 13, 2013, and the [NPCC Glossary of Terms](#) dated Oct. 26, 2011 included in the Meeting Materials.

1. **Introductions. Antitrust Guidelines, Agenda, Roster**
 - a. Attendee introductions.
 - b. RSC Roster changes.
 - c. Read Antitrust Guidelines.
 - d. Review of Agenda--inclusions, deletions.
2. **Review of Previous RSC Meeting Minutes** (in Meeting Materials Package)
 - a. Approval of Minutes of Nov. 29-30, 2012 RSC Meeting.

3. Action and Ongoing Items List (in Meeting Materials Package)

Description	Owner	Due	Status
Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Outgrowth of RSC/CC joint session April 21, 2010.
New York Adoption of More Stringent/Specific NPCC Criteria	Diane Barney	RSC Meeting	Ongoing

- a. NPCC Members on NERC Drafting Teams.
- b. Review Executive Tracking Summary.

4. Items Requiring RSC Approval

- a.

5. FERC

- a. Issuances below.

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.1	Comments	RM12-12-000	Reply Comments Of The North American Electric Reliability Corporation In Response To Notice Of Proposed Rulemaking	12/11/12
	<u>Summary, Instructions, Dates =></u>	NERC provides these reply comments in response to the comments submitted on November 26, 2012 on FERC's September 20, 2012, NOPR regarding the proposed regional Reliability Standard PRC-006-NPCC-1 (Automatic Underfrequency Load Shedding).		
5.2	Letter Order	RD12-6-000	Approval of Interpretation to Reliability Standard CIP-004	12/12/12
	<u>Summary, Instructions, Dates =></u>	On August 1, 2012, the NERC submitted a petition proposing to approve an Interpretation of Requirements R2, R3, and R4 to Reliability Standard CIP-004-4. The proposed interpretation clarifies that all cyber access must be authorized, and all authorized cyber access requires compliance with Requirements R2, R3, and R4 of CIP-004-4.		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.3	Final Rule	RM12-9-000	Regional Reliability Standard PRC-006-SERC-01- Automatic Underfrequency Load Shedding Requirements	12/20/12
	<u>Summary, Instructions, Dates =></u>	FERC approves Regional Reliability Standard PRC-006-SERC-01 (Automatic Underfrequency Load Shedding Requirements). Regional Reliability Standard PRC-006-SERC-01 is designed to ensure that automatic underfrequency load shedding protection schemes, designed by planning coordinators and implemented by applicable distribution providers and transmission owners in the SERC Reliability Corporation Region, are coordinated to mitigate the consequences of an underfrequency event effectively. FERC approves the related VRFs, with one modification, VSLs, implementation plan, and effective date proposed by NERC.		
5.4	Order	RR12-8-000	Order Conditionally Approving Revisions To North American Electric Reliability Corporation Rules Of Procedure	12/20/12
	<u>Summary, Instructions, Dates =></u>	On May 7, 2012, NERC filed a petition requesting approval of revisions to provisions in Sections 300 (Reliability Standards Development), 400 (Compliance Enforcement), 600 (Personnel Certification), 800 (Reliability Assessment and Performance Analysis), 1000 (Situation Awareness and Infrastructure Security), 1400 (Amendments to the Rules of Procedure), and 1700 (Challenges to Determinations) of the NERC Rules of Procedure. The petition also sought to revise NERC Rules of Procedure Appendices 2 (Definitions), 3C (Procedure for Coordinating Reliability Standards Approvals, Remands, and Directives), 4B (Sanction Guidelines), 4C (Uniform Compliance Monitoring and Enforcement Program (CMEP)), 5B (Statement of Compliance Registry Criteria), and 6 (System Operator Certification Program Manual). Pursuant to section 215(f) of the Federal Power Act (FPA), FERC conditionally approved the proposed revisions to the Rules of Procedure, with limited exceptions.		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.5 (refer to Item 5.13 below)	Final Rule	RM12-6-000, RM12-7-000; Order No. 773	Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure	12/20/12; 1/4/13
	<u>Summary, Instructions, Dates =></u>	FERC approves modifications to the currently effective definition of “bulk electric system” developed by NERC. FERC finds that the modified definition of “bulk electric system” removes language allowing for regional discretion in the currently-effective bulk electric system definition and establishes a bright-line threshold that includes all facilities operated at or above 100 kV. The modified definition also identifies specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of “bulk electric system.” In this Final Rule, FERC also approves: (1) NERC’s revisions to its Rules of Procedure, which create an exception process to add elements to, or remove elements from, the definition of “bulk electric system” on a case-by-case basis; (2) NERC’s form entitled “Detailed Information to Support an Exception Request” that entities will use to support requests for exception from the “bulk electric system” definition; and (3) NERC’s implementation plan for the revised “bulk electric system” definition.		
5.6	Comments	RM12-4-000	Comments Of The North American Electric Reliability Corporation In Response To Notice Of Proposed Rulemaking	12/21/12
	<u>Summary, Instructions, Dates =></u>	NERC provides these comments on the NOPR regarding NERC’s proposed Reliability Standard FAC-003-2 (Transmission Vegetation Management) issued by the FERC in this proceeding on October 18, 2012. In the NOPR, FERC proposes to approve Reliability Standard FAC-003-2, which modifies the currently effective Reliability Standard, FAC-003-1. FERC also proposes to approve changes in the definition of “Right-of-Way” and “Vegetation Inspection,” the addition of the term “Minimum Vegetation Clearance Distance” (“MVCD”), the implementation plan for proposed FAC-003-2, and the Violation Severity Levels associated with the proposed Reliability Standard. Finally, FERC proposes to direct NERC to revise the VRF for R2, and approve the remainder		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
		of the VRFs. In response to FERC's request for comments, NERC addresses several sections of the NOPR.		
5.7	Informational Filing	RM05-17-000, RM05-25-000, RM06-16-000	North American Electric Reliability Corporation Reliability Standards Development Plan 2013-2015 Informational Filing Pursuant To Section 310 Of The NERC Rules Of Procedure	12/31/12
	<u>Summary, Instructions, Dates =></u>	NERC submits to FERC for informational purposes its Reliability Standards Development Plan in accordance with Section 310 of the NERC Rules of Procedure. The NERC Board of Trustees approved the 2013 Development Plan on December 19, 2012.		
5.8	Petition	RD13-	<u>Petition Of The North American Electric Reliability Corporation For Approval Of Proposed Reliability Standard EOP-004-2 – Event Reporting</u>	12/31/12
	<u>Summary, Instructions, Dates =></u>	NERC requests that FERC approve the proposed Reliability Standard - EOP-004-2 - Event Reporting. EOP-004-2 was approved by the NERC Board of Trustees on November 7, 2012. NERC is requesting approval of the proposed Reliability Standard, the associated implementation plan, Violation Risk Factors (“VRFs”) and Violation Severity Levels (“VSLs”), and retirement of the currently effective Reliability Standards EOP-004-1 - Disturbance Reporting, and CIP-001-2a - Sabotage Reporting.		
5.9	Errata Petition	RD13-3-000	Errata to Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard EOP-004-2 – Event Reporting Docket No. RD13-3-000	1/4/13
	<u>Summary, Instructions, Dates =></u>	On December 31, 2012, NERC filed a Petition for Approval of Proposed Reliability Standard EOP-004-2 – Event Reporting. It has come to NERC's attention that Exhibit B - <i>Proposed Reliability Standard EOP-004-2 Submitted for Approval</i> , contains a minor error. A corrected copy of this Exhibit is attached. The revision is changing “table below”		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
		to “standard” in the Note for Attachment A on page 8 of 22 of the Standard.		
5.10	Comments	AD12-12-000	Comments Of The North American Electric Reliability Corporation-- Coordination Between Natural Gas And Electricity Markets	1/7/13
	<u>Summary, Instructions, Dates =></u>	NERC is providing these comments in response to the FERC Notice of Request for Comments and Technical Conference on the Coordination between Natural Gas and Electricity Markets. NERC’s mission, as the FERC-designated ERO, is to ensure the reliability of the Bulk Power System in North America, in part, by developing and enforcing mandatory Reliability Standards. NERC’s reliability mandate under Section 215 of the Federal Power Act does not include authority to monitor and enforce market-based issues. Accordingly, NERC’s comments herein focus on electric and gas industry coordination issues as they relate to electric reliability.		
5.11	Comments	RM12-22-000	Reply Comments Of The North American Electric Reliability Corporation In Response To Notice Of Proposed Rulemaking	1/10/13
	<u>Summary, Instructions, Dates =></u>	NERC provides these comments in response to comments submitted on FERC’s October 18, 2012, Notice of Proposed Rulemaking (“NOPR”) proposing to direct NERC to file for approval with FERC Reliability Standards that address the risks posed by geomagnetic disturbances (“GMDs”) to the reliable operation of the Bulk Power System, in two stages.		
5.12	Order	FA11-21-000	Order Approving Settlement Agreement	1/16/13
	<u>Summary, Instructions, Dates =></u>	FERC approves the attached Settlement Agreement between the Office of Enforcement (Enforcement) and NERC. This Order is in the public interest because it comprehensively resolves all outstanding issues between the Parties related to Enforcement’s findings and recommendations arising out of its 2012 performance audit of NERC.		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.13 (refer to Item 5.5 above)	Request for Clarification	RM12-6- 000, RM12-7- 000	Request For Clarification Of The North American Electric Reliability Corporation	1/22/13
	<u>Summary, Instructions, Dates =></u>	NERC requests clarification of FERC's December 20, 2012 Order on Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure ("Order No. 773") (see Item 5.5 above). There are several areas where NERC requests FERC to clarify its interpretation of the BES Definition in Order No. 773. (1) clarification of the FERC directive to revise Exclusion E3; and (2) clarification of the FERC directives to: (a) implement Exclusion E1 so that the exclusions for radial systems do not apply to tie-lines for BES generators identified in inclusion I2, and (b) implement Exclusion E3 so that the exclusion for local networks does not apply to BES generator tie-lines operated at or above 100 kV.		
5.14	Quarterly Report	RM06-16- 010, RM06-16- 011	Quarterly Report Of The North American Electric Reliability Corporation On Status Of Development Of Bal-003	1/23/13
	<u>Summary, Instructions, Dates =></u>	On March 30, 2012, NERC filed with FERC a motion for an extension of time to submit a revised Resource and Demand Balancing ("BAL") Reliability Standard on Frequency Response and Frequency Bias, BAL-003. On May 4, 2012, FERC issued an order establishing a compliance schedule for NERC to submit a revised BAL-003 consistent with the Commission's directives in Order No. 693. FERC established a deadline of May 31, 2013, and directed the submission of informational reports on a quarterly basis describing "the progress NERC is making toward completing its analysis and research as well as the progress it is making in completing work on the other issues and filing a revised BAL-003-0 Reliability Standard by May 31, 2013." The instant filing is submitted in compliance with the Commission's directive in the May 4 Order.		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.15	Reply Comments	RD13-2-000	Reply Comments Of The North American Electric Reliability Corporation	1/23/13
	<u>Summary, Instructions, Dates =></u>	On November 21, 2012, NERC submitted a petition for approval of proposed Reliability Standard VAR-002-2b. The proposed VAR-002-2b Reliability Standard ensures that generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection. On January 8, 2013, the PPL Companies submitted comments requesting that the Commission modify the Violation Severity Level (“VSL”) for Requirement R2. Pursuant to Rules 212 and 213 of FERC, NERC hereby provides reply comments in response.		
5.16	Analysis	RR06-1-000, RR09-7-000	Analysis of NERC Standard Process Results, Fourth Quarter 2012	1/31/13
	<u>Summary, Instructions, Dates =></u>	NERC submits its Analysis of NERC Standards Process Results for the Second Quarter 2012 (“Ballot Results Analysis”). This filing is submitted in response to FERC’s January 18, 2007 Order requiring NERC to closely monitor and report the voting results for NERC Reliability Standards each quarter for three years and FERC’s subsequent Order issued on September 16, 2010, whereby the Commission renewed and expanded on its directive for an additional three years. The Ballot Results Analysis addresses ballot results during the October 1, 2012 through December 31, 2012 timeframe, and includes NERC’s analysis of the voting results, including trends and patterns of stakeholder approval of NERC Reliability Standards.		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.17	Petition	RD13-	Petition Of The North American Electric Reliability Corporation For Approval Of Critical Infrastructure Protection Reliability Standards Version 5	1/31/13
	<u>Summary, Instructions, Dates =></u>	NERC hereby requests that FERC approve ten proposed CIP Reliability Standards (CIP Version 5”). NERC also requests approval of the proposed definitions of terms used in the proposed CIP Version 5, the associated implementation plan, and the proposed VRFs and VSLs. This filing also addresses all remaining standards-related issues and directives from Order No. 706. Additionally, NERC requests that CIP Version 5 become effective on the first day of the eighth calendar quarter after a final rule is issued in this docket.		
5.18	Motion	RM12-4-000	Motion For Leave To File Reply Comments And Reply Comments Of The North American Electric Reliability Corporation Regarding Comments Received On Notice Of Proposed Rulemaking	2/5/13
	<u>Summary, Instructions, Dates =></u>	In response to comments submitted to FERC regarding the NOPR issued on October 18, 2012, NERC submits this Motion for Leave to File Reply Comments and Reply Comments. NERC provides these reply comments as the FERC certified ERO responsible for the development and enforcement of mandatory Reliability Standards, including proposed FAC-003-2. On December 21, 2012, NERC submitted comments addressing several sections of the Commission’s NOPR. A number of other entities also filed comments. NERC respectfully requests that FERC consider NERC’s reply comments clarifying and responding to certain issues raised by commenters. FERC should accept these reply comments because they provide information to assist FERC in this proceeding.		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.19	Petition	RD13-	Petition Of The North American Electric Reliability Corporation For Approval Of Interpretation To Bal-002-1 – Disturbance Control Performance	2/12/13
	<u>Summary, Instructions, Dates =></u>	NERC hereby requests FERC approve a proposed interpretation to Reliability Standard —BAL-002-1– Disturbance Control Performance, which was approved by the NERC Board of Trustees on November 7, 2012. Upon FERC approval of the interpretation, the standard will be referred to as BAL-002-1a.		

6. Posted NERC Projects (in Meeting Materials Package)

- A table of past ballot recommendations (in the Supplement) is periodically being posted on the [NPCC Website](#).
- [Project 2010-11– TPL Table 1 Order TPL-002-2b, footnote ‘b’ and TPL-001-3, footnote 12 recirculation ballot results](#).
- NERC seeking a NPCC member for the [Project 2008-02 - Undervoltage Load Shedding](#) Drafting Team.

	<u>Project and Supporting Materials</u>	<u>Current and Pending Ballots</u>		<u>Join Ballot Pools</u>		<u>Posted for Comment</u>	
1.	Project 2010-05.1 – Protection Systems: Phase 1(Misoperations) PRC-004-3 Related Files Paul DiFilippo to call in 10:30 a.m. 2/20/13 to discuss.	Successive Ballot	Non-Binding Poll			1/22/13	2/20/13
		Start	End				
		2/11/13	2/20/13				
2.	Project 2007-09 - Generator Verification - PRC-024-1 Related Files	Successive Ballot	Non-Binding Poll			1/25/13	2/25/13
		Start	End				
		2/15/13	2/25/13				

	<u>Project and Supporting Materials</u>	<u>Current and Pending Ballots</u>		<u>Join Ballot Pools</u>		<u>Posted for Comment</u>	
3.	Project 2010-13.2 Phase 2 of Relay Loadability: Generation (Also Cost Effectiveness, Supplemental SAR, RSAW Comment Forms) <u>NOTE: First CEAP Posting</u> Related Files	Initial Ballot					
		3/1/13	3/11/13	1/25/13	2/25/13	1/25/13	3/11/13
4.	Rapid Revision Procedure					2/5/13	3/6/13
5.	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot					
		3/13/13	3/22/13	2/6/13	3/7/13	2/6/13	3/22/13
6.	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot					
		3/13/13	3/22/13	2/6/13	3/7/13	2/6/13	3/22/13

Items 6 Table 5, 6--TFIST meeting Feb. 19-20, 2013. Preparing ballot recommendation.

7. **Current NERC Drafting Team Nominations**

a.				

8. **NERC Meetings** (in Meeting Materials Package)

- a. NERC Definition of BES Standard Drafting Team.
 1. Conference call Dec. 4, 2012.
 2. Pete Heidrich (FRCC) discussion.
- b. Standards Committee Special Election--closes Feb. 25, 2013.
- c. Standards Committee Meeting.
 1. Jan. 16-17, 2013 Meeting. David Kiguel's Meeting notes.
 2. SCPS update.
- d. NERC 2013 Reliability Standards and Compliance Spring Workshop--March 19-21, 2013, St. Louis, Mo.
- e. Member Representatives Committee.
 1. [Jan. 16, 2013.](#)
 2. [Jan. 30, 2013 Conference Call.](#)
 3. [Feb. 6, 2013.](#)
 - a. [Presentations.](#)

- f. [Standards Oversight and Technology Committee Meeting--Feb. 6, 2013.](#)
 - 1. [Presentations.](#)
- g. [Corporate Governance and Human Resources Committee Meeting--Feb. 6, 2013.](#)
 - 1. [Presentations.](#)
- h. NERC Board of Trustees Conference Call--Dec. 19, 2012.
 - 1. [Dec. 19, 2012 Conference Call.](#)
 - 2. [Feb. 7, 2013 Meeting--Standards approved by the Board.](#)
- i. [Lessons Learned--Feb. 18, 2013](#)--discuss ways to improve standards.
- j. System Protection and Control Subcommittee--Feb. 5-7, 2013 Meeting notes (Quoc Le).

9. NERC Compliance Activity (in Meeting Materials Package)

a.

	<u>Draft CANs--Table</u>	<u>Posted</u>	<u>Comments Due</u>

10. NERC Items of Interest

- a. [Winter Preparation for Severe Weather Event.](#)
- b. [Reliability Assurance Initiative--Concept White Paper posted.](#)
- c. Proposal for NERC CEAP pilot project--Project 2010-13.2 Generator Relay Loadability, GMD standard.
- d. NERC 2013 Reliability Standards and Compliance Workshops--[March 19-21, 2013](#); September 24-26, 2013.
- e. Brian Murphy (NextEra Energy, Inc.) Chairman of NERC's Standards Committee--discuss NERC's Standard Processes Manual, NERC's Standard's Committee (1:00 p.m. Feb. 20, 2013).
- f. NERC 2014 Business Plan and Budget Schedule.
- g. NERC Single Portal Project.

11. NPCC Regional Standards, Directories and Related Items (in Meeting Materials Package)

- a. Responses to Request for Criteria Interpretation.
 - 1. Clarification of the criteria surrounding Section 5.6.2 of Directory#3 Maintenance Criteria for Bulk Power System Protection (completed Dec. 20, 2012).
 - 2. Clarification of the criteria surrounding Section 5.7.1 of Directory#3 Maintenance Criteria for Bulk Power System Protection (completed Dec. 20, 2012).
- b. Directories.
 - 1. Directory#12--[Automatic UFLS Program Requirements](#) posted for comment in the NPCC Open Process through March 14, 2013.

2. Directory#1--Design and Operation of the BPS. Status of Joint CO-7/CP-11 Review.
3. Directory#7--SPS. Status of TFSP Review.
- c. RCC.
 1. Scope.
 2. Feb. 27, 2013 Meeting--
- d. Regional Reliability Standards Process Manual.
- e. PRC-002-NPCC-01--Disturbance Monitoring.
 1. Utility Services Request for Interpretation.
 2. Daren Verner (TFSP) RSAR.
- f. NPCC Board of Directors Jan. 30, 2013 Meeting.
 1. RSC Status Report.
 2. NPCC 2013 Corporate Goals.

12. **Other Items of Interest**

- a. Regional Standards Committee Work Plan for Calendar Years 2013-2014.
- b. Review of [NPCC Triage Process for Standards Related Matters](#).
- c. [Régie de l'énergie](#) approved the reliability standards pre-filing [consultation process](#). Si-Truc Phan to discuss. The following link is for additional supporting materials:

<https://neptune.npcc.org:443/AHT/DownloadLogin.aspx?package=728fSSgzhZqw1EhjZG1aAd7YEEYI7jr1M2wEiKha4ztX2LIGDwfmro8rg1tBYOsMIVvtbuUhaq8BwD5lZZd7nUsMFYQRuWcdo2M1ZsjQzbM4%3d>

13. **Future NPCC Meetings**

RSC 2013/14 Meeting Dates

April 10-11, 2013 NPCC Offices, New York
June 19- 20, 2013 Saratoga, New York
August 21-22, 2013 Toronto
Oct. 9-10, 2013 Montreal
Dec. 5-6, 2013 (General Meeting Dec. 4, 2013) Boston, Mass.
Feb. 19-20, 2014 NextEra Energy Offices--to be confirmed

2013 RSC Conference Call Schedule
(call 719-785-1707, Guest Code 8287#)

March 6, 2013	March 22, 2013
April 5, 2013	April 26, 2013
May 10, 2013	May 24, 2013
June 7, 2013	July 5, 2013
July 19, 2013	August 2, 2013
August 16, 2013	September 6, 2013
September 20, 2013	October 4, 1013
October 25, 2013	November 8, 2013
November 22, 2013	December 20, 2013

BOD 2013 Meeting Dates

March 12, 2013 –BES Implementation Teleconference
April 30, 2013 – Teleconference
June 25, 2013
August 6, 2013 – Teleconference
September 10, 2013
October 29, 2013 – Teleconference
December 4, 2013

RCC, CC, and Task Force Meeting Dates--2013

RCC	Feb. 27, June 5, September 11, December 3
CC	
TFSS	March 19-20, May 22-23, July 24-25, September 25-26, November 13-14
TFCP	May 8, August 14, November 6
TFCO	March 20-21, May 15-16, August 28-29, Oct. 17-18, Dec. 5-6
TFIST	May 28-29, September 12-13
TFSP	March 26-28, May 14-16, July 23-25, Sept. 17-19, Nov. 19-21

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, Andrianne S. Payson at 212-335-4765.

Glossary of Terms Used in NERC Reliability Standards

Updated February 11, 2013

Introduction:

This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through February 11, 2013.

This reference is divided into two sections, and each section is organized in alphabetical order. The first section identifies all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the second section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards. (WECC, NPCC and ReliabilityFirst are the only Regions that have definitions approved by the NERC Board of Trustees. If other Regions develop definitions for approved Regional Standards using a NERC-approved standards development process, those definitions will be added to the Regional Definitions section of this glossary.)

Most of the terms identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to this glossary following board adoption, with the "FERC approved" date added following a final Order approving the definition.

Immediately under each term is a link to the archive for the development of that term.

Definitions that have been adopted by the NERC Board of Trustees but have not been approved by FERC, or FERC has not approved but has directed be modified, are shaded in blue. Definitions that have been remanded or retired are shaded in orange.

Any comments regarding this glossary should be reported to the following:
sarcomm@nerc.com with "Glossary Comment" in the subject line.

Continent-wide Definitions:

A.....	4
B.....	8
C.....	17
D.....	22
E.....	25
F.....	28
G.....	32
H.....	33
I.....	34
J.....	37
L.....	38
M.....	38
N.....	40
O.....	43
P.....	47
R.....	52
S.....	58
T.....	61
V.....	65
W.....	65
Y.....	65

Regional Definitions:

Reliability*First* Regional Definitions..... 66

NPCC Regional Definitions 67

WECC Regional Definitions 68

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Adequacy [Archive]		2/8/2005	3/16/2007	The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact [Archive]		2/7/2006	3/16/2007	The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Adverse Reliability Impact [Archive]		8/4/2011		The impact of an event that results in Bulk Electric System instability or Cascading.
After the Fact [Archive]	ATF	10/29/2008	12/17/2009	A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement [Archive]		2/8/2005	3/16/2007	A contract or arrangement, either written or verbal and sometimes enforceable by law.
Alternative Interpersonal Communication [Archive]		11/7/2012		Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Altitude Correction Factor [Archive]		2/7/2006	3/16/2007	A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service [Archive]		2/8/2005	3/16/2007	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. <i>(From FERC order 888-A.)</i>
Anti-Aliasing Filter [Archive]		2/8/2005	3/16/2007	An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error [Archive]	ACE	2/8/2005	3/16/2007	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Area Control Error [Archive]	ACE	12/19/2012		The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Area Interchange Methodology [Archive]		08/22/2008	11/24/2009	The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has received the Interchange information (initial or revised).
Automatic Generation Control [Archive]	AGC	2/8/2005	3/16/2007	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.
Available Flowgate Capability [Archive]	AFC	08/22/2008	11/24/2009	A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability [Archive]	ATC	2/8/2005	3/16/2007	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Available Transfer Capability [Archive]	ATC	08/22/2008	11/24/2009	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.
Available Transfer Capability Implementation Document [Archive]	ATCID	08/22/2008	11/24/2009	A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.
ATC Path [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path ¹ .

¹ See 18 CFR 37.6(b)(1)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Balancing Authority [Archive]	BA	2/8/2005	3/16/2007	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Base Load [Archive]		2/8/2005	3/16/2007	The minimum amount of electric power delivered or required over a given period at a constant rate.
BES Cyber Asset [Archive]		11/26/12		A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems. (A Cyber Asset is not a BES Cyber Asset if, for 30 consecutive calendar days or less, it is directly connected to a network within an ESP, a Cyber Asset within an ESP, or to a BES Cyber Asset, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
BES Cyber System [Archive]		11/26/12		One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.
BES Cyber System Information [Archive]		11/26/12		Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BES Cyber System Information may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Blackstart Capability Plan [Archive]		2/8/2005 Will be retired when EOP-005-2 becomes enforceable on (7/1/13)	3/16/2007	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Blackstart Resource [Archive]		8/5/2009	3/17/11	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
Block Dispatch [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System [Archive]	BES	2/8/2005	3/16/2007	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System [Archive]	BES	01/18/2012	07/01/2013	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. Inclusions: • I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3. • I2 - Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. • I3 - Blackstart Resources identified in the Transmission Operator's restoration plan. • I4 - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System (Continued)	BES			I5 –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1. Exclusions: • E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating). Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System (Continued)	BES			• E2 - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. • E3 - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System (Continued)	BES			a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating) ; b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). • E4 – Reactive Power devices owned and operated by the retail customer solely for its own use. Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Burden [Archive]		2/8/2005	3/16/2007	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices [Archive]		8/22/2008	Not approved; Modification directed 11/24/09	Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Bus-tie Breaker [Archive]		8/4/2011		A circuit breaker that is positioned to connect two individual substation bus configurations.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Capacity Benefit Margin [Archive]	CBM	2/8/2005	3/16/2007	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Benefit Margin Implementation Document [Archive]	CBMID	11/13/2008	11/24/2009	A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency [Archive]		2/8/2005	3/16/2007	A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading [Archive]		2/8/2005	3/16/2007	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Cascading Outages [Archive]		11/1/2006 Withdrawn 2/12/2008	FERC Remanded 12/27/2007	~~The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.~~
CIP Exceptional Circumstance [Archive]		11/26/12		A situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.
CIP Senior Manager [Archive]		11/26/12		A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC CIP Standards, CIP-002 through CIP-011.
Clock Hour [Archive]		2/8/2005	3/16/2007	The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration [Archive]		2/8/2005	3/16/2007	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor [Archive]		2/8/2005	3/16/2007	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Confirmed Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has verified the Arranged Interchange.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Congestion Management Report [Archive]		2/8/2005	3/16/2007	A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Consequential Load Loss [Archive]		8/4/2011		All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
Constrained Facility [Archive]		2/8/2005	3/16/2007	A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency [Archive]		2/8/2005	3/16/2007	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve [Archive]		2/8/2005	3/16/2007	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Contract Path [Archive]		2/8/2005	3/16/2007	An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Control Center [Archive]		11/26/12		One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.
Control Performance Standard [Archive]	CPS	2/8/2005	3/16/2007	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan [Archive]		2/7/2006	3/16/2007	A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path [Archive]		5/2/2006	3/16/2007	A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Critical Assets [Archive]		5/2/2006	1/18/2008	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets [Archive]		5/2/2006	1/18/2008	Cyber Assets essential to the reliable operation of Critical Assets.
Curtailment [Archive]		2/8/2005	3/16/2007	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Curtailment Threshold [Archive]		2/8/2005	3/16/2007	The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets [Archive]		5/2/2006	1/18/2008	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Assets [Archive]		11/26/12		Programmable electronic devices, including the hardware, software, and data in those devices.
Cyber Security Incident [Archive]		5/2/2006	1/18/2008	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.
Cyber Security Incident [Archive]		11/26/12		A malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, • Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Delayed Fault Clearing [Archive]		11/1/2006	12/27/2007	Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand [Archive]		2/8/2005	3/16/2007	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management [Archive]	DSM	2/8/2005	3/16/2007	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Dial-up Connectivity [Archive]		11/26/12		A data communication link that is established when the communication equipment dials a phone number and negotiates a connection with the equipment on the other end of the link.
Direct Control Load Management [Archive]	DCLM	2/8/2005	3/16/2007	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
Dispatch Order [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Dispersed Load by Substations [Archive]		2/8/2005	3/16/2007	Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor [Archive]	DF	2/8/2005	3/16/2007	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).
Distribution Provider [Archive]	DP	2/8/2005	3/16/2007	Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Disturbance [Archive]		2/8/2005	3/16/2007	1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard [Archive]	DCS	2/8/2005	3/16/2007	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Disturbance Monitoring Equipment [Archive]	DME	8/2/2006	3/16/2007	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders²: • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions
Dynamic Interchange Schedule or Dynamic Schedule [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Dynamic Transfer [Archive]		2/8/2005	3/16/2007	The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.

² Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Economic Dispatch [Archive]		2/8/2005	3/16/2007	The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electronic Access Control or Monitoring Systems [Archive]	EACMS	11/26/12		Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Devices.
Electronic Access Point [Archive]	EAP	11/26/12		A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.
Electrical Energy [Archive]		2/8/2005	3/16/2007	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter [Archive]	ESP	5/2/2006	1/18/2008	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Electronic Security Perimeter [Archive]	ESP	11/26/12		The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.
Element [Archive]		2/8/2005	3/16/2007	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Emergency or BES Emergency [Archive]		2/8/2005	3/16/2007	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency Request for Interchange [Archive]	Emergency RFI	10/29/2008	12/17/2009	Request for Interchange to be initiated for Emergency or Energy Emergency conditions.
Energy Emergency [Archive]		2/8/2005	3/16/2007	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Equipment Rating [Archive]		2/7/2006	3/16/2007	The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
External Routable Connectivity [Archive]		11/26/12		The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Existing Transmission Commitments [Archive]	ETC	08/22/2008	11/24/2009	Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Facility [Archive]		2/7/2006	3/16/2007	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.)
Facility Rating [Archive]		2/8/2005	3/16/2007	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault [Archive]		2/8/2005	3/16/2007	An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk [Archive]		2/7/2006	3/16/2007	The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand [Archive]		2/8/2005	3/16/2007	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service [Archive]		2/8/2005	3/16/2007	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover [Archive]		2/7/2006	3/16/2007	An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate [Archive]		2/8/2005	3/16/2007	A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Flowgate [Archive]		08/22/2008	11/24/2009	1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.
Flowgate Methodology [Archive]		08/22/2008	11/24/2009	The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
Forced Outage [Archive]		2/8/2005	3/16/2007	1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias [Archive]		2/8/2005	3/16/2007	A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Bias Setting [Archive]		2/8/2005	3/16/2007	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Bias Setting [Archive]		2/7/2013		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's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.
Frequency Deviation [Archive]		2/8/2005	3/16/2007	A change in Interconnection frequency.
Frequency Error [Archive]		2/8/2005	3/16/2007	The difference between the actual and scheduled frequency. ($F_A - F_S$)
Frequency Regulation [Archive]		2/8/2005	3/16/2007	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response [Archive]		2/8/2005	3/16/2007	(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Response Measure [Archive]	FRM	2/7/2013		The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.
Frequency Response Obligation [Archive]	FRO	2/7/2013		The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Response Sharing Group [Archive]	FRSG	2/7/2013		A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.
Generator Operator [Archive]	GOP	2/8/2005	3/16/2007	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner [Archive]	GO	2/8/2005	3/16/2007	Entity that owns and maintains generating units.
Generator Shift Factor [Archive]	GSF	2/8/2005	3/16/2007	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor [Archive]	GLDF	2/8/2005	3/16/2007	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Generation Capability Import Requirement [Archive]	GCIR	11/13/2008	11/24/2009	The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Host Balancing Authority [Archive]		2/8/2005	3/16/2007	1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value [Archive]		2/8/2005	3/16/2007	Data measured on a Clock Hour basis.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Implemented Interchange [Archive]		5/2/2006	3/16/2007	The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange [Archive]		2/8/2005	3/16/2007	The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. ($I_A - I_S$)
Independent Power Producer [Archive]	IPP	2/8/2005	3/16/2007	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc. [Archive]	IEEE	2/7/2006	3/16/2007	
Interactive Remote Access [Archive]		11/26/12		User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate Device and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interchange [Archive]		5/2/2006	3/16/2007	Energy transfers that cross Balancing Authority boundaries.
Interchange Authority [Archive]	IA	5/2/2006	3/16/2007	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interchange Distribution Calculator [Archive]	IDC	2/8/2005	3/16/2007	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.
Interchange Schedule [Archive]		2/8/2005	3/16/2007	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction [Archive]		2/8/2005	3/16/2007	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag [Archive]		2/8/2005	3/16/2007	The details of an Interchange Transaction required for its physical implementation.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interconnected Operations Service [Archive]		2/8/2005	3/16/2007	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection [Archive]		2/8/2005	3/16/2007	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection Reliability Operating Limit [Archive]	IROL	2/8/2005	3/16/2007 Retired 12/27/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.
Interconnection Reliability Operating Limit [Archive]	IROL	11/1/2006	12/27/2007	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages ³ that adversely impact the reliability of the Bulk Electric System.
Interconnection Reliability Operating Limit T _v [Archive]	IROL T _v	11/1/2006	12/27/2007	The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T _v shall be less than or equal to 30 minutes.

³ On September 13, 2012, FERC issued an Order approving NERC's request to modify the reference to "Cascading Outages" to "Cascading outages" within the definition of IROL due to the fact that the definition of "Cascading Outages" was previously remanded by FERC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Intermediate Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.
Intermediate System [Archive]		11/26/12		A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.
Interpersonal Communication [Archive]		11/7/2012		Any medium that allows two or more individuals to interact, consult, or exchange information.
Interruptible Load or Interruptible Demand [Archive]		11/1/2006	3/16/2007	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.
Joint Control [Archive]		2/8/2005	3/16/2007	Automatic Generation Control of jointly owned units by two or more Balancing Authorities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Limiting Element [Archive]		2/8/2005	3/16/2007	The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load [Archive]		2/8/2005	3/16/2007	An end-use device or customer that receives power from the electric system.
Load Shift Factor [Archive]	LSF	2/8/2005	3/16/2007	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity [Archive]	LSE	2/8/2005	3/16/2007	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Long-Term Transmission Planning Horizon [Archive]		8/4/2011		Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.
Market Flow [Archive]		11/4/2010	4/21/2011	The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.
Minimum Vegetation Clearance Distance [Archive]	MVCD	11/3/2011		The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Misoperation [Archive]		2/7/2006	3/16/2007	- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. - Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). - Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Native Load [Archive]		2/8/2005	3/16/2007	The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon [Archive]		1/24/2011	11/17/2011	The transmission planning period that covers Year One through five.
Net Actual Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load [Archive]		2/8/2005	3/16/2007	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service [Archive]		2/8/2005	3/16/2007	Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Non-Consequential Load Loss [Archive]		8/4/2011		Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.
Non-Firm Transmission Service [Archive]		2/8/2005	3/16/2007	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve [Archive]		2/8/2005	3/16/2007	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Clearing [Archive]		11/1/2006	12/27/2007	A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator [Archive]		5/2/2007	10/16/2008	Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power) [Archive]		5/2/2007	10/16/2008	The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Nuclear Plant Licensing Requirements [Archive]	NPLRs	5/2/2007	10/16/2008	Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Interface Requirements [Archive]	NPIRs	5/2/2007	10/16/2008	The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Off-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service [Archive]	OASIS	2/8/2005	3/16/2007	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff [Archive]	OATT	2/8/2005	3/16/2007	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Plan [Archive]		2/7/2006	3/16/2007	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. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Procedure [Archive]		2/7/2006	3/16/2007	A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process [Archive]		2/7/2006	3/16/2007	A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve [Archive]		2/8/2005	3/16/2007	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Reserve – Supplemental [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage [Archive]		2/7/2006	3/16/2007	The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis [Archive]		10/17/2008	3/17/2011	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Outage Transfer Distribution Factor [Archive]	OTDF	8/22/2008	11/24/2009	In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Overlap Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Participation Factors [Archive]		8/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand [Archive]		2/8/2005	3/16/2007	1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period [Archive]		2/7/2006	3/16/2007	The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Access Control Systems [Archive]	PACS	11/26/12		Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Physical Security Perimeter [Archive]	PSP	5/2/2006	1/18/2008	The physical, completely enclosed (“six-wall”) border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Physical Security Perimeter [Archive]	PSP	11/26/12		The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Planning Assessment [Archive]		8/4/2011		Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority [Archive]	PA	2/8/2005	3/16/2007	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Coordinator [Archive]	PC	8/22/2008	11/24/2009	See Planning Authority.
Point of Delivery [Archive]	POD	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt [Archive]	POR	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point to Point Transmission Service [Archive]	PTP	2/8/2005	3/16/2007	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Postback [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Power Transfer Distribution Factor [Archive]	PTDF	08/22/2008	11/24/2009	In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pro Forma Tariff [Archive]		2/8/2005	3/16/2007	Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protected Cyber Assets [Archive]	PCA	11/26/12		One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP. A Cyber Asset is not a Protected Cyber Asset if, for 30 consecutive calendar days or less, it is connected either to a Cyber Asset within the ESP or to the network within the ESP, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Protection System [Archive]		2/7/2006	3/17/2007 Will be retired 4/1/2013	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System ⁴ [Archive] [Implementation Plan]		11/19/2010	2/3/2012	Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

⁴ This term becomes effective on April 1, 2013.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System Maintenance Program [Archive]	PSMP	11/7/2012		An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities: Verify — Determine that the component is functioning correctly. Monitor — Observe the routine in-service operation of the component. Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. Inspect — Examine for signs of component failure, reduced performance or degradation. Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
Pseudo-Tie [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a “virtual” tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Purchasing-Selling Entity [Archive]	PSE	2/8/2005	3/16/2007	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Ramp Rate or Ramp [Archive]		2/8/2005	3/16/2007	(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions [Archive]		2/7/2006	3/16/2007	The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate
Rating [Archive]		2/8/2005	3/16/2007	The operational limits of a transmission system element under a set of specified conditions.
Rated System Path Methodology [Archive]		08/22/2008	11/24/2009	The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reactive Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that supplies energy to the load.
Reallocation [Archive]		2/8/2005	3/16/2007	The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time [Archive]		2/7/2006	3/16/2007	Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment [Archive]		10/17/2008	3/17/2011	An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Receiving Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority importing the Interchange.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Regional Reliability Organization [Archive]	RRO	2/8/2005	3/16/2007	1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan [Archive]		2/8/2005	3/16/2007	The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve [Archive]		2/8/2005	3/16/2007	An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Service [Archive]		2/8/2005	3/16/2007	The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment RFI [Archive]		10/29/2008	12/17/2009	Request to modify an Implemented Interchange Schedule for reliability purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Coordinator [Archive]	RC	2/8/2005	3/16/2007	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System [Archive]	RCIS	2/8/2005	3/16/2007	The system that Reliability Coordinators use to post messages and share operating information in real time.
Reliability Directive [Archive]		8/16/2012		A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.
Remedial Action Scheme [Archive]	RAS	2/8/2005	3/16/2007	See "Special Protection System"
Reportable Cyber Security Incident [Archive]		11/26/12		A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reportable Disturbance [Archive]		2/8/2005	3/16/2007	Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.
Request for Interchange [Archive]	RFI	5/2/2006	3/16/2007	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
Reserve Sharing Group [Archive]	RSG	2/8/2005	3/16/2007	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Resource Planner [Archive]	RP	2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Response Rate [Archive]		2/8/2005	3/16/2007	The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way [Archive]	ROW	2/7/2006	3/16/2007	A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Right-of-Way [Archive]	ROW	11/3/2011		The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.
Right-of-Way [Archive]	ROW	5/9/12		The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Scenario [Archive]		2/7/2006	3/16/2007	Possible event.
Schedule [Archive]		2/8/2005	3/16/2007	(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency [Archive]		2/8/2005	3/16/2007	60.0 Hertz, except during a time correction.
Scheduling Entity [Archive]		2/8/2005	3/16/2007	An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path [Archive]		2/8/2005	3/16/2007	The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority exporting the Interchange.
Sink Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Special Protection System (Remedial Action Scheme) [Archive]	SPS	2/8/2005	3/16/2007	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.
Spinning Reserve [Archive]		2/8/2005	3/16/2007	Unloaded generation that is synchronized and ready to serve additional demand.
Stability [Archive]		2/8/2005	3/16/2007	The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit [Archive]		2/8/2005	3/16/2007	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition [Archive]	SCADA	2/8/2005	3/16/2007	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Surge [Archive]		2/8/2005	3/16/2007	A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage [Archive]		2/7/2006	3/16/2007	The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System [Archive]		2/8/2005	3/16/2007	A combination of generation, transmission, and distribution components.
System Operating Limit [Archive]	SOL	2/8/2005	3/16/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator [Archive]		2/8/2005	3/16/2007	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Telemetry [Archive]		2/8/2005	3/16/2007	The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating [Archive]		2/8/2005	3/16/2007	The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line [Archive]		2/8/2005	3/16/2007	A circuit connecting two Balancing Authority Areas.
Tie Line Bias [Archive]		2/8/2005	3/16/2007	A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error [Archive]		2/8/2005	3/16/2007	The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction [Archive]		2/8/2005	3/16/2007	An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
TLR Log [Archive]		2/8/2005	3/16/2007	Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.
Total Flowgate Capability [Archive]	TFC	08/22/2008	11/24/2009	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Transfer Capability [Archive]	TTC	2/8/2005	3/16/2007	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction [Archive]		2/8/2005	3/16/2007	See Interchange Transaction.
Transfer Capability [Archive]		2/8/2005	3/16/2007	The measure of the ability of interconnected electric systems to move or transfer power <i>in a reliable manner</i> from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is <i>not</i> generally equal to the transfer capability from "Area B" to "Area A."

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transfer Distribution Factor [Archive]		2/8/2005	3/16/2007	See Distribution Factor.
Transmission [Archive]		2/8/2005	3/16/2007	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint [Archive]		2/8/2005	3/16/2007	A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer [Archive]		2/8/2005	3/16/2007	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line [Archive]		2/7/2006	3/16/2007	A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator [Archive]	TOP	2/8/2005	3/16/2007	The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Operator Area [Archive]		08/22/2008	11/24/2009	The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner [Archive]	TO	2/8/2005	3/16/2007	The entity that owns and maintains transmission facilities.
Transmission Planner [Archive]	TP	2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
Transmission Reliability Margin [Archive]	TRM	2/8/2005	3/16/2007	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Reliability Margin Implementation Document [Archive]	TRMID	08/22/2008	11/24/2009	A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service [Archive]		2/8/2005	3/16/2007	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider [Archive]	TSP	2/8/2005	3/16/2007	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Vegetation [Archive]		2/7/2006	3/16/2007	All plant material, growing or not, living or dead.
Vegetation Inspection [Archive]		2/7/2006	3/16/2007	The systematic examination of a transmission corridor to document vegetation conditions.
Vegetation Inspection [Archive]		11/3/2011		The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Vegetation Inspection [Archive]		5/9/12		The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Wide Area [Archive]		2/8/2005	3/16/2007	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.
Year One [Archive]		1/24/2011	11/17/2011	The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

ReliabilityFirst Regional Definitions

The following definitions were developed for use in ReliabilityFirst Regional Standards.

RFC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Resource Adequacy [Archive]		08/05/2009	03/17/2011	The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand [Archive]		08/05/2009	03/17/2011	Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period [Archive]		08/05/2009	03/17/2011	A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur
Wind Generating Station [Archive]		11/03/2011		A collection of wind turbines electrically connected together and injecting energy into the grid at one point, sometimes known as a "Wind Farm."
Year One [Archive]		08/05/2009	03/17/2011	The planning year that begins with the upcoming annual Peak Period

NPCC Regional Definitions

The following definitions were developed for use in NPCC Regional Standards.

NPCC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Current Zero Time [Archive]		11/04/2010	10/20/2011	The time of the final current zero on the last phase to interrupt.
Generating Plant [Archive]		11/04/2010	10/20/2011	One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

WECC Regional Definitions

The following definitions were developed for use in WECC Regional Standards.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Area Control Error [†] [Archive]	ACE	3/12/2007	6/8/2007	Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.
Automatic Generation Control [‡] [Archive]	AGC	3/12/2007	6/8/2007	Means equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.
Automatic Time Error Correction [Archive]		3/26/2008	5/21/2009	A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection's scheduled frequency.
Automatic Time Error Correction [Archive]		12/19/2012		The addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error.
Average Generation [‡] [Archive]		3/12/2007	6/8/2007	Means the total MWh generated within the Balancing Authority Operator's Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).
Business Day [†] [Archive]		3/12/2007	6/8/2007	Means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Commercial Operation [Archive]		10/29/2008	4/21/2011	Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
Contributing Schedule [Archive]		2/10/2009	3/17/2011	A Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.
Dependability-Based Misoperation [Archive]		10/29/2008	4/21/2011	Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Disturbance [†] [Archive]		3/12/2007	6/8/2007	Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Extraordinary Contingency [†] [Archive]		3/12/2007	6/8/2007	Shall have the meaning set out in Excuse of Performance, section B.4.c. language in section B.4.c: <i>means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).</i>
Frequency Bias [†] [Archive]		3/12/2007	6/8/2007	Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.
Functionally Equivalent Protection System [Archive]	FEPS	10/29/2008	4/21/2011	A Protection System that provides performance as follows: • Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards. • Each Protection System may have different components and operating characteristics.
Functionally Equivalent RAS [Archive]	FERAS	10/29/2008	4/21/2011	A Remedial Action Scheme ("RAS") that provides the same performance as follows: • Each RAS can detect the same conditions and provide

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
				mitigation to comply with all Reliability Standards. • Each RAS may have different components and operating characteristics.
Generating Unit Capability [†] [Archive]		3/12/2007	6/8/2007	Means the MVA nameplate rating of a generator.
Non-spinning Reserve [†] [Archive]		3/12/2007	6/8/2007	Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.
Normal Path Rating [†] [Archive]		3/12/2007	6/8/2007	Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.
Operating Reserve [†] [Archive]		3/12/2007	6/8/2007	Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.
Operating Transfer Capability Limit [†] [Archive]	OTC	3/12/2007	6/8/2007	Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Primary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).
Qualified Controllable Device [Archive]		2/10/2009	3/17/2011	A controllable device installed in the Interconnection for controlling energy flow and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.
Qualified Transfer Path [Archive]		2/10/2009	3/17/2011	A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.
Qualified Transfer Path Curtailment Event [Archive]		2/10/2009	3/17/2011	Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1) during which the curtailment tool is functional.
Relief Requirement [Archive]		2/10/2009	3/17/2011	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
Secondary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of area (i).
Security-Based Misoperation		10/29/2008	4/21/2011	A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
[Archive]				and is the measure of a device's certainty not to operate falsely.
Spinning Reserve [†] [Archive]		3/12/2007	6/8/2007	Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).
Transfer Distribution Factor [Archive]	TDF	2/10/2009	3/17/2011	The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]
WECC Table 2 [†] [Archive]		3/12/2007	6/8/2007	Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

Endnotes

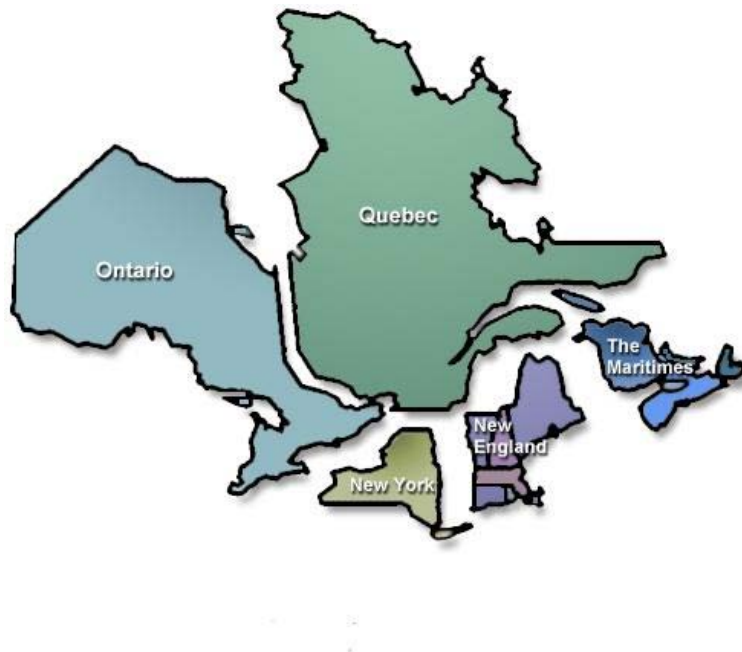
[†] FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009.



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

Northeast Power Coordinating Council, Inc.

Glossary of Terms



Approved by the Reliability Standards Committee

October 26, 2011

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Actual Interchange		Metered electric power that flows from one entity to another.	D5
Applicable emergency limits		These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc. Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes. The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system stability performance, and should not adversely affect the operation of the bulk power system. The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment ratings are found elsewhere in this glossary.)	D1 D7
Area		An Area (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as control areas as defined by the North American Electric Reliability Council (NERC) (the definition can be found in this glossary).	D1 D7 D8 D12
Area Control Error	ACE	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error. (Source: NERC Glossary of Terms)	D2 D5 D8

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Automatic Generation Control	AGC	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. (Source: NERC Glossary of Terms)	D2 D5 D8
Basic Minimum Power System		Consists of one or more generating stations, transmission lines, and substations operating in the form of an island for the purpose of initiating the restoration process. The Reliability Coordinator and Transmission Operator shall each identify its area's basic minimum power system(s) within its system restoration plan.	D8
Bipolar		Operation of HVdc with two poles of opposite polarity with negligible ground current.	D1
Blackstart Capability		The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.	D8
Bulk Power System	BPS	The interconnected electrical systems within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area .	D1 D2 D3 D4 D7 D9 D10
Cable		An underground or underwater circuit.	D4 D5 D7 D8

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Capacity		The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation , transmission, or other electrical equipment.	D1 D2 D5 D8
Commutation Failure		A fault in a thyristor valve group where the current transfer from one valve to the next is interrupted.	D4
Component		Refers to components of equipment or protection systems rather than elements of a power system. See Element .	D1 D3 D7
Contingency		An event, usually involving the loss of one or more elements , which affects the power system at least momentarily.	D1 D2 D5 D7
Converter		An operative unit comprised of either a rectifier or inverter bridge connected to an ac system through transformers and switching devices with the associated control equipment.	D4
Converter Transformer		A power transformer which transfers the energy from the thyristor valves to the connected ac system and vice-versa.	D4
Critical Components		Equipment required for continued and proper operation of a key facility in the event of a total loss of grid supply. Critical components include but are not limited to the following: ▪ blackstart generating units; ▪ substation backup power supplies; ▪ control center and telecommunication center backup power supplies and computer systems;	D8

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		- control center and telecommunication center computer room HVAC; - telecommunication facilities backup power supplies.	
Declared Capability (of a generator or generating facility)		The facility ratings submitted by the Generator Owner to the respective Transmission Operator as per NERC Standard FAC-009.	D10
Delayed Fault Clearing		Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay. (Source: NERC Glossary of Terms)	D1
Demand		- The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. - The rate at which energy is being used by the customer. (Source: NERC Glossary of Terms)	D1 D5
Disturbance		Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by faults .	D1 D2 D4 D5 D7
Disturbance Monitoring Equipment	DME	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders² - Sequence of event recorders which record equipment response to the event; - Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective	D4

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		relays; Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions (Source: NERC Glossary of Terms)	
Economic Dispatch		The allocation of demand to individual generating units on line to effect the most economical production of electricity. (Source: NERC Glossary of Terms)	D2
Element		Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components. (Source: NERC Glossary of Terms)	D1 D2 D4 D5 D7 D9 D10
Emergency		Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system. <u>NPCC Specific Definition:</u> Emergency — An Emergency is considered to exist in an Area if firm load may have to be shed.	D1 D2 D4 D5 D7
Emergency Regional Reserve Redispatch		The regional coordination of actions to enhance reliability among Areas in response to a Regional Reserve Deficiency .	D5

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Emergency Regional Reserve Dispatch Energy		Electrical energy that is received and delivered among Areas in response to a Regional Reserve Deficiency to enhance regional reliability .	D5
Emergency Transfer Capability		The amount of power transfer allowed between Areas or within an Area when operating to meet NPCC emergency criteria contingencies [as defined in Directory #1].	D2
Energize		To make a piece of equipment or circuit alive.	D4
Fault		An electrical short circuit .	D1 D4 D7
Firm Capacity		Capacity that is as firm as the seller's native load unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting reserve is carried by the seller.	D1
Firm Load		That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions. (Source: Firm Demand defined in NERC Glossary of Terms)	D1 D2
First Contingency Loss		The largest capacity outage including any assigned Ten-Minute Reserve which would result from the loss of a single element .	D5
Forced Outage		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure. (Source: NERC Glossary of Terms)	D1
Generation (Electricity)		The process of producing electrical energy from other forms of energy;	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh). Gross Generation — The electrical output at the terminals of the generator, usually expressed in megawatts (MW). Net Generation — Gross generation minus station service or unit service power requirements, usually expressed in megawatts (MW).	D2 D4 (Appendix A) D5 D7 (Appendices) D12
Generation Facility		Generating units, which are modeled as a single entity by the Transmission Operator.	D8 D9 D10
Generation Rejection		The process of deliberately removing preselected generation from a power system, or initiating HVdc power runback, in response to a contingency or an abnormal condition in order to maintain the integrity of the system. Synonym: Generator Dropping.	D1 D7
Gross Real Power Capability (of a generator or generating facility)		The maximum megawatt output at the generator terminals, at the normally expected system conditions for that seasonal capability period.	D9
Gross Reactive Power Capability (of a generator or generating facility)		The maximum lagging and leading reactive capability at the generator terminals and at a specified Gross Real Power output for a specific seasonal capability period.	D10
Grounded		Connected to earth or some extended conducting body that serves instead of the earth, whether the connection is intentional or accidental.	D4 D7
Harmonic		A sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency. Note: For example, a component, the frequency of which is twice the fundamental frequency, is called a second harmonic.	D4
HVdc Link		A high Voltage direct current connection between two power systems often	D4

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		used to interconnect two asynchronous power systems.	
Inadvertent Interchange		The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (IA – IS) (Source: NERC Glossary of Terms)	D5
Interconnection		When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Québec, and Alaska. When not capitalized, the facilities that connect two systems or Control Areas . Additionally, an interconnection refers to the facilities that connect a nonutility generator to a Control Area or system.	D1 D2 D5 D8 D12
Interchange		Energy transfers that cross Balancing Authority boundaries. (Source: NERC Glossary of Terms)	D1 (Appendix B) D2 D5
Interchange Schedule		An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction. (Source: NERC Glossary of Terms)	D1 D5
Interface		The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.	D1 (Appendices)
Interruptible Load		Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (Source: NERC Glossary of Terms)	D1 (Appendix D) D5
Island		A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission	D1 D8

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		system elements .	D12
Key Facilities		Facilities required to establish a basic minimum power system following a system blackout. These facilities are essential to the restoration plan of the Control Area and include generating stations having blackstart units and other selected generating stations, transmission elements which are part of the basic minimum power system , control centers and telecommunication centers and telecommunication facilities which are necessary to support protection and control facilities, voice and data between and within control centers and voice and data between control centers and key generating / transmission substations.	D8
Load		An end-use device or customer that receives power from the electric system. (Source: NERC Glossary of Terms)	D1 D2 D3 D4 D5 D7 (Appendices) D8 D9 D10 D12
Load Relief		Load reduction accomplished by voltage reduction and/or load shedding .	D1
Load Shedding		The process of deliberately removing (either manually or automatically) preselected customers' load from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.	D2 D3 D4 D12
Local area		An electrically confined or radial portion of the system. The geographic	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.	D4
Maintenance Outage		The removal of equipment from service availability to perform work on specific elements that can be deferred, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.	D1
Net Capacity		The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.	D1
Net Real Power Capability (of a generator or generating facility)		The Gross Real Power Capability, less the auxiliary real power loads necessary to operate the generator at maximum real power output.	D9
Net Reactive Power Capability (of a generator or generating facility)		The Gross Reactive Power Capability adjusted for any applicable losses and auxiliary loads incurred up to the point of interconnection and at a specified Gross Real Power output for a specific seasonal capability period.	D10
Normal Fault Clearing		Fault clearing consistent with correct operation of the protection system and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system .	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Normal (Precontingency) Operating Procedures		Operating procedures that are normally invoked by the system operator to alleviate potential facility overloads or other potential system problems in anticipation of a contingency .	D1 (Appendix F)
Normal Transfer Capability		The amount of power transfer allowed between Areas or within an Area when operating to meet NPCC normal criteria contingencies [as defined in Directory #1].	D1 D2
Operating Capability		The maximum load carrying ability of generating equipment or other electrical apparatus under specified conditions for a given time interval.	D9
Operating Limit		The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre- contingency criteria as determined by equipment loading capability and acceptable voltage conditions; (b) stability criteria; (c) post- contingency loading and voltage criteria.	D1 (Appendix C) D2 D5
Operating Capacity		The capacity claimed for any generating source recognizing any temporary deratings, governor load limits, proven maximum loading rates, starting times and equipment limitations including transmission operating limits .	D5
Operating Procedures		A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.	D1 D5 D7
Operating Reserve		The sum of ten-minute and thirty-minute reserve .	D1 D2
Phase Shifting Transformer		A transformer that advances or retards the phase angle relationship of one circuit with respect to another to control power flow. Synonyms: Phase angle regulator, phase shifter.	D1 D2 D4
Pilot Protection		A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.	D4
Planned Outage		Removing the equipment from service availability for inspection and/or general overhaul of one or more major equipment groups. This outage	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		usually is scheduled well in advance.	
Pole (HVdc term)		A rectifier and an inverter, with associated filter banks and control equipment, tied together by a transmission line or bus.	D1
Power		See definitions for Real Power and Reactive Power.	D8
Power Swing		A transient change in the power flows on a system, usually of an oscillatory nature.	D1 D4 (Appendix A)
Protected element		The power system element protected by the subject protection system . Examples: Line, bus, transformer, generator.	D4
Protection		The provisions for detecting power system faults or abnormal conditions and taking appropriate automatic corrective action.	D1 D2 D3 D4 D7
Protection group		A fully integrated assembly of protective relays and associated equipment that is designed to perform the specified protective functions for a power system element , independent of other groups. <u>Notes:</u> (a) Various identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2. (b) Pilot protection is considered to be one protection group.	D1 D3 D4 D7
Protection System		<u>Element Basis</u>	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at <u>all terminals</u> of a power system element to provide the complete protection of that element. <u>Terminal Basis</u> One or more protection groups, as above, installed at <u>one</u> terminal of a power system element, typically a transmission line.	D3 D4 D7
Protective relay		A relay that detects a power system fault or abnormal condition and initiates appropriate control system action.	D3 D4
Rating		The operational limits of an electric system, facility, or element under a set of specified conditions.	D1 D5
Reactive Power		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers , or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVar).	D1 D2 D10
Real Power		The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).	D1 D2

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
			D9 D10
Reclosing		Autoreclosing — The automatic closing of a circuit breaker in order to restore an element to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers. High-speed autoreclosing — The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit fault arc deionization with due regard to coordination with all relay protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle. Manual Reclosing — The closing of a circuit breaker by operator action after it has been tripped by protective relays. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised. Supervision — A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., synchronism-check). Synchronism-check — refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.	D1
Regional Reserve Deficiency		When two or more Areas are deficient in ten minute reserve after all Area coordinated actions have been deployed, including acquiring emergency energy and/or capacity but excluding the shedding of firm load.	D5
Relay		An electrical device designed to respond to input conditions in a prescribed	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see protective relay).	D3 D4 D7 D12
Reliability		The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — Adequacy and Security. Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Security — The ability of the electric system to withstand disturbances such as electric short circuits or unanticipated loss of system elements.	D1 D2 D5 D9 D10
Reportable Events		System disturbances involving losses of load, generation or transmission facilities within NPCC Control Areas which equal or exceed the following criteria are reportable events: (1) Actual net interchange deviations equal to or greater than 500 MW (Maritime: 300 MW). (2) Loss of generation or load equal to or greater than 500 MW (Maritime: 300 MW). (3) System frequency deviations equal to or greater than 0.03 Hz (Hydro-Quebec: 0.5 Hz). (System frequency deviations that occur for events outside of the NPCC are reported for analysis of frequency response, but are not included in the reporting for the NERC Disturbance Control Standard.)	D5

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Reserve		In normal usage, reserve is the amount of capacity available in excess of the demand	D1 D2 D5
Reserve on Automatic Generation Control (AGC)		That portion of synchronized reserve which is under the command of an automatic controller to respond to load without need for manual action.	D5
Reserve Requirement		That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area supply adequacy.	D2 D5
Resource		Resource refers to the total contributions provided by supply-side and demand -side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand -side facilities include measures for reducing load , such as conservation, demand management, and interruptible load .	D1 D2 D5 D8 D9 D10
Scheduled Interchange		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time. (Source: Net Scheduled Interchange defined in NERC Glossary of Terms)	D5
Second Contingency Loss		The largest capacity outage which would result from the loss of a single element after allowing for the First Contingency Loss.	D5
Short Circuit		An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between two points of different potential. <i>Note:</i> The term fault or short-circuit fault is used to describe a short circuit.	D4 D7
Short Time Emergency Rating	STE	The maximum loading of electrical equipment which can be sustained for 15 minutes based on nominal ambient conditions and recognizing preloading conditions.	D1 (Appendix C)

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Significant Adverse Impact		With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact: a. instability; • any instability that cannot be demonstrably contained to a well-defined local area. • any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area b. unacceptable system dynamic response; • an oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event. c. unacceptable equipment tripping • tripping of an un-faulted bulk power system element (element that has already been classified as bulk power system) under planned system configuration due to operation of a protection system in response to a stable power swing • operation of a Type I or Type II Special Protection System in response to a condition for which its operation is not required d. voltage levels in violation of applicable emergency limits; e. loadings on transmission facilities in violation of applicable emergency limits.	D1 (Appendix E) D5
Single Contingency		A single event, which may result in the loss of one or more elements .	D5
Special Protection System	SPS	Special Protection System (SPS) – A protection system designed to detect abnormal system conditions and take corrective action other than the	D1 D3

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. However, the following are not considered SPS's: - Automatic underfrequency load shedding; - Automatic under voltage load shedding, and - Manual or automatic locally controlled shunt devices.	D4 (Appendix A) D7
Stability		The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: NERC Glossary of Terms)	D1 D4
Static Var Compensator	SVC	A combination of controlled shunt reactors and switched capacitor banks, used to affect the reactive power flow of the system or to regulate the system voltage.	D1 (Appendix G) D2 D4
Synchronize		The process of connecting two previously separated alternating current apparatuses or systems after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).	D8

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
Synchronized Reserve		The unused portion of generating capacity which is synchronized to the system and ready to pick up load to claimed capacity and capacity which can be made available by curtailing pumping hydro units.	D5
Synchronous Condenser		A synchronous machine which operates without mechanical load to supply or absorb reactive power for voltage control purposes.	D2 D10
System Disturbance		An event characterized by one or more of the following phenomena: the loss of power system stability ; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.	D1 D2 D4 D5 D7
System Operator		An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time. (Source: NERC Glossary of Terms)	D2 D3 D8
Teleprotection		A form of protection that uses a communication channel.	D4 D7
Ten-Minute Reserve		The sum of synchronized and non- synchronized reserve that is fully available in ten minutes.	D1 D5
Thirty-Minute Reserve		The sum of synchronized and non- synchronized reserve that can be utilized in thirty minutes, excluding capacity assigned to ten-minute reserve .	D5
Tie Line		A circuit connecting two Balancing Authority Areas.	D1 D2 (Appendix B) D5
Tie Line Bias		A mode of operation under automatic generation control in which the area control error is determined by the actual net interchange minus the biased	D2

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		scheduled net interchange .	
Total Transfer Capability	TTC	The amount of electric power that can be transferred over the interconnected transmission network in a <i>reliable</i> manner based on <i>all</i> of the following conditions: 1. For the existing or planned system configuration, and with normal (precontingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits. 2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit. 3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits 4. With reference to condition 1 above, in the case where precontingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached. 5. In some cases, individual system, power pool, subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of	D5

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Directories that use this term
		transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive than the single contingency considerations described above, the more restrictive reliability criteria or guides must be observed.	
Transfer Capability		The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is not generally equal to the transfer capability from “Area B” to “Area A.” (Source: NERC Glossary of Terms)	D1 D2 D5
Transient Stability		The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance and to regain a state of equilibrium following that disturbance.	D1
Verified Capability (of a generator or generating facility)		The capability as demonstrated by the methods specified in NPCC Directories and accepted by the Transmission Operator.	D9 D10
Voltage Reduction		A means to reduce the demand by lowering the customer’s voltage.	D1 D2 (Appendix B) D5 (Appendix 3)
Voltage Regulating Transformer		A transformer that increases or decreases the voltage magnitude relationship of one circuit with respect to another, most often used to control voltage but also to control reactive power flow.	D1
With Due Regard To Reclosing		This phrase means that before any manual system adjustments, recognition will be given to the type of reclosing (i.e., manual or automatic) and the kind of protection .	D1

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
Automatic Operating Systems		Special protection systems , remedial action schemes, or other operating systems installed on the electric systems that require <i>no intervention</i> on the part of system operators .	
Auto-reclosing		The automatic closing of a circuit breaker in order to restore an element to service following automatic tripping of the circuit breaker. Auto-reclosing does not include automatic closing of capacitor or reactor circuit breakers.	
Available Transfer Capability	ATC	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the Transmission Reliability Margin (TRM) , less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM) .	
Availability		A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.	
Average Demand		The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.	
Base load Capacity		Capacity used to serve an essentially constant level of customer demand . Base load generating units typically operate whenever they are available.	
Billing Demand		The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.	
Bottled Energy/Power/Capacity		Energy/Power/Capacity which is available at the source but which cannot be delivered to the point of use because of restrictions in the transmission	

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
		system. Also referred to as Locked-In Energy/Power/Capacity.	
Capacity Benefit Margin	CBM	CBM is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.	
Coincident Demand		The sum of two or more demands that occur in the same demand interval.	
Contingency Reserve Adjustment Factor		A factor used in determining the additional ten-minute reserve that each Area , not meeting the DCS requirement for a given quarter, must carry. It is calculated using the following formula: $CRA_{\text{quarter}} = 2 - \{\text{the average percentage DCS (expressed as a decimal) for the quarter of measurement}\}$	
Continuous Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand indefinitely without loss of equipment life. (Normally not used in NPCC)	
Contract Demand		The amount of capacity that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.	
Control Area		An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its net interchange schedule with other Control Areas and contributing to frequency regulation of the Interconnection .	
Demand Interval		The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.	

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
Double Element Contingency		A contingency involving the loss of two elements .	
Emergency Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or element can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.	
Firm Demand		That portion of the Contract Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.	
First Contingency Incremental Transfer Capability	FCITC	The amount of power, incremental above normal base power transfers, that can be transferred over the transmission network in a reliable manner based on the following conditions: 1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits. 2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric element, such as a transmission line, transformer, or generating unit. 3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency	

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
		ratings and all voltages are within emergency limits.	
First Contingency Total Transfer Capability	FCTTC	The algebraic sums of the FCITC values and the appropriate total interregional transfers assumed in the base load flow model used for the FCITC calculations.	
Forced Outage Rate		The hours a generating unit, transmission line, or other facility is forced out of service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.	
Harmonic Current		A periodic component of current having a frequency that is an integral multiple of that currents fundamental frequency. Harmonic currents are normally measured in amperes or in percent of the fundamental frequency current, generally at specific frequencies, such as second and third harmonics. Harmonic currents can, for example, be generated by HVdc converters, Static Var Compensators (SVC) and geomagnetically induced currents (GIC).	
High Speed Fault Clearing		Fault clearing consistent with correct operation of high-speed relays and the associated circuit breakers without intentional time delay. <i>Notes:</i> The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.	
High-Speed Auto reclosing		The auto reclosing of a circuit breaker after a necessary time delay (less than one second) to permit fault arc deionization with due regard to coordination with all relay protective systems. This type of auto reclosing is generally not supervised by voltage magnitude or phase angle.	
Integrated Demand		The average of the instantaneous demands over the demand interval.	

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
Interchange Scheduling		The actions taken by scheduling entities to arrange transfer of electric power . The schedule consists of an agreement on the amount, start and end times, ramp rate, and degree of firmness.	
Instantaneous Demand		The rate of energy delivered at a given instant.	
Limiting Contingency		The contingency which establishes the transfer capability .	
Load Cycle		The normal pattern of demand over a specified time period associated with a device or circuit.	
Long Time Emergency (LTE) Rating		The maximum rating of electrical equipment based on nominal ambient conditions and recognizing the nominal load cycle for a long period such as 24 hours.	
Manual Reclosing		The closing of a circuit breaker by operator action after it has been tripped by protective relays . Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.	
Negative Shared Activation Reserve Energy		Energy received by an assisting Area from a contingent Area for an eligible resource loss having a concurrent effective loss of demand that exceeds the loss of energy from the resource loss, and is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent Area requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent Area which have resulted in mutually established interchange schedules .	
Non coincident Demand		The sum of two or more demands that occur in different demand intervals.	
Non recallable Available Transfer Capability	NATC	Total Transmission Capability less the Transmission Reliability Margin , less non recallable reserved transmission service (including the Capacity Benefit Margin).	
Non-Synchronized Reserve		That portion of operating capacity , which is available for synchronizing to	

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
		the network and that capacity which can be made available by applying load management techniques such as curtailing interruptible loads or implementing voltage reductions .	
Normal Incremental Transfer Capability	NITC	The amount of electric power , incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre- contingency loadings reach the normal thermal rating of a facility prior to any first contingency transfer limits being reached. When this occurs, NITC replaces FCITC as the most limiting transfer capability.	
Normal Rating		The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.	
NPCC Emergency Criteria Contingencies		The set of contingencies to be observed when operating the bulk power system under emergency conditions.	
NPCC Normal Criteria Contingencies		The set of contingencies to be observed when operating the bulk power system under normal conditions.	
Peak Demand		The highest electric power requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.	
Peaking Capacity		Capacity used to serve peak demand . Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.	
Permanent Fault		A fault which prevents the affected element from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.	

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
Pole (of an ac switching device)		That portion of the device associated exclusively with one electrically separated conducting path of the main circuit of the device.	
Post contingency Operating Procedures		Operating procedures that may be invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred.	
Power		Apparent Power — The product of the volts and amperes. It comprises both <i>real</i> and <i>reactive</i> power, usually expressed in kilo volt amperes (kVA) or megavoltamperes (MVA).	
Power Pool		Two or more interconnected electric systems operated and/or planned to supply power for their combined demand requirements.	
Recallable Available Transmission Capability	RATC	Total Transmission Capability less the Transmission Reliability Margin , less recallable transmission service, less non-recallable transmission service (including the Capacity Benefit Margin).	
Reclosing <i>This term by itself is not defined in the NPCC glossary.</i>		<i>Need to develop this definition.</i>	
Regional Reserve Sharing		Procedure that allows participating Areas to reduce the requirement for reserve within its Area due to the availability and deliverability of reserve from other Areas .	
Regional Reserve Sharing Energy		Energy delivered to a contingent Area from assisting Areas that is converted from delivered Shared Activation Reserve Energy after the Shared Activation Reserve Energy has been delivered for 30 minutes; maintained until the Contingent Area requests a return to normal but not longer than sixty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent Area which have resulted in mutually established interchange schedules .	
Shared Activation Reserve Energy		Energy delivered from an assisting Area to a contingent Area that is implemented at a zero time ramp rate immediately following allocation	

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
		notification, maintained until the Contingent Area requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent Area which have resulted in mutually established interchange schedules .	
Single Element Contingency		A contingency involving the loss of one element .	
Small-Signal Stability		The ability of the electric system to withstand small changes or disturbances without the loss of synchronism among the synchronous machines in the system.	
Stability Limit		See NERC definition.	
Supervision		A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., synchronism-check).	
Supervisory Control		A form of remote control comprising an arrangement for the selective control of remotely located facilities by an electrical means over one or more communications media.	
Surge		See NERC definition.	
Synchronism-check		Refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.	
Synchronism-check Relay		A verification relay whose function is to operate when two input voltages satisfy predetermined operating parameters.	
Transient Fault		A fault which occurs for a short or limited time, or which disappears when the faulted element is separated from all electrical sources and which does not require repairs to be made before the element can be returned to service either manually or automatically.	

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Acronym	Definition	Documents that use this term
Transmission Reliability Margin	TRM	TRM is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.	
Wheeling		The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.	

Note: Terms highlighted in blue are defined differently in the NERC Glossary of Terms

Term	Regional Standard	Acronym	BOT Approved Date	FERC Approved Date	Definition
Current Zero Time (Archive)	PRC-002-NPCC-01	DM	11/04/2010	10/20/2011	The time of the final current zero on the last phase to interrupt. (Source: NERC Glossary of Terms)
Generating Plant (Archive)	PRC-002-NPCC-01	DM	11/04/2010	10/20/2011	One or more generators at a single physical location whereby any single contingency can affect all the generators at that location. (Source: NERC Glossary of Terms)



1040 Avenue of the Americas - 10th Floor
New York, New York 10018-3703

NPCC Regional Standards Committee
Draft Minutes
Meeting # 12-6

Nov. 29, 2012 8:00 a.m. - 5:00 p.m.
Nov. 30, 2012 8:00 a.m. - 12:00 p.m.

Hotel Omni Mont Royal
1050 Sherbrooke Street West
Montreal, Quebec
Tel: 514-284-1110

Dress Business Casual

RSC@npcc.org

Call in 719-785-1707, Guest Code 8287#

Note: For reference. [Glossary of Terms Used in NERC Reliability Standards](#) dated Oct. 19, 2012, and the [NPCC Glossary of Terms](#) dated Oct. 26, 2011 included in the Meeting Materials.

Items in red from the Nov. 29, 2012 session.

Items in green from the joint RSC/CC Nov. 30, 2012 session.

Guy Zito called the meeting to order at 08:00 a.m.

Stan Kopman called the joint RSC/CC meeting to order at 08:05 a.m. See Item 12 below.

Attendees

	<u>Name</u>	<u>Organization</u>	<u>Sector</u>
1.	Guy Zito	Northeast Power Coordinating Council	
2.	Lee Pedowicz	Northeast Power Coordinating Council	
3.	Si-Truc Phan	Hydro-Quebec TransEnergie	2
4.	Don Weaver	New Brunswick System Operator	2
5.	David Kiguel	Hydro One Networks Inc.	1
6.	Greg Campoli	New York Independent System Operator	2
7.	Gerry Dunbar	Northeast Power Coordinating Council	
8.	Brian Shanahan	National Grid	1
9.	Brian Robinson	Utility Services	5
10.	Roger Champagne (guest)	Régie de l'énergie	
11.	Michaël Godbout (guest)	Régie de l'énergie	
12.	Michael Jones	National Grid	3
13.	Kathleen Goodman	ISO - New England	2
14.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	1
15.	Howard Gugel (guest)	NERC	
16.	Mike Garton	Dominion Resources Services, Inc.	4
17.	Kal Ayoub (guest)	FERC	
18.	Manon Paquet (guest)	Hydro-Quebec Production	
19.	Chantal Mazza (guest)	Hydro-Quebec TransEnergie	
20.	Joel Charlebois (guest)	AESI	
21.	David Ramkalawan	Ontario Power Generation, Inc.	4
22.	Robert Pellegrini	The United Illuminating Company	1
23.	Kristin Halper (11/29 Only)	Northeast Power Coordinating Council	
24.	Ben Li (guest)	Consultant	
25.	Randy Macdonald	New Brunswick Power Transmission	1
26.	Randy Crissman (guest)	New York Power Authority	
27.	Ben Wu	Orange and Rockland Utilities, Inc.	1

On the Phone

	<u>Name</u>	<u>Organization</u>	<u>Sector</u>
1.	Bruce Metruck	New York Power Authority	5
2.	Nicholas Occhionero (guest)(11/29 Only)	State of New York Public Service Commission	
3.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	1
4.	Peter Yost (11/30 only)	Consolidated Edison Co. of New York, Inc.	3

1. Introductions. Antitrust Guidelines, Agenda, Roster

- a. Attendee introductions.
Attendees introduced themselves.
- b. RSC Roster changes.
 1. New RSC member Christy Koncz--PSEG.
 2. Brian Shanahan--National Grid.
- c. Read Antitrust Guidelines.
Lee Pedowicz read the Antitrust Guidelines.
- d. Review of Agenda--inclusions, deletions.
Guy Zito went over Agenda. A representative from Hydro-Quebec will attend to give a presentation on Geomagnetic Disturbances later in the meeting.

2. Review of Previous RSC Meeting Minutes *(in Meeting Materials Package)*

- a. Approval of Minutes of previous RSC Meeting.
The minutes of the Sept. 5-6, 2012 RSC Meeting were discussed. Mike Garton made a motion to accept the Minutes as read. Kathleen Goodman seconded. All were in favor of accepting the Minutes as read.

3. Action and Ongoing Items List (in Meeting Materials Package)

Description	Owner	Due	Status
Coordination with the Compliance Committee to develop Joint Activity Action List	Greg Campoli	RSC Meeting	Outgrowth of RSC/CC joint session April 21, 2010.
New York Adoption of More Stringent/Specific NPCC Criteria	Diane Barney	RSC Meeting	Ongoing

Guy Zito began the discussion, and then passed it on to Greg Campoli. Greg Campoli is the coordinator of Standards with Compliance. As of this meeting there are no issues that need to be considered. There is a need to consider where the existing Directories stand in the development process. Guy Zito would like to see the CC get more involved in the comment process. He asked if the CC could get more involved with the comment process, and if there was any value in it. Greg Campoli said that there would be value. David Kiguel commented that RSAWs are going to be developed the same time as standards. Guy Zito mentioned that the NPCC Disturbance Monitoring Standard will be discussed at the joint RSC/CC Meeting the next day, as well as Directory items.

a. NPCC Members on NERC Drafting Teams.

Mike Jones described the changes listed at the bottom of the spreadsheet. Guy Zito remarked that he is trying to get NPCC participation on all Drafting Teams. Kathleen Goodman commented that maybe all that is necessary is to just follow project progress instead of participating members. Ben Li countered that it is still beneficial to follow the members on Drafting Teams. Guy Zito hoped that NPCC members on the Drafting Teams would be sounding board for the RSC. Unfortunately that hasn't always been the case.

b. Review Executive Tracking Summary.

Guy Zito announced that Michael Lombardi is no longer on the RSC because of the Northeast Utilities merger with NSTAR. Looking for someone to take responsibility for maintaining the Executive Tracking Summary. He hoped that it would be someone outside of NPCC Staff. The latest version of the Executive Tracking summary has been posted. (See Item 4a).

c. Periodically post the table of past ballot recommendations (in the Supplement) on the NPCC Website.

Guy Zito stated that the table of ballot recommendations in the Supplement would give valuable information to the RSC members, and suggested that it be posted on the NPCC Website. David Kiguel asked if the ballot recommendations (shown in the table) are public information. Guy Zito said that they were. There is not a confidentiality issue with posting the table.

4. Items Requiring RSC Approval

- a. Vice-chair to replace Michael Lombardi.

Guy Zito said that Bruce Metruck is interested in becoming the Vice-chair. Guy Zito asked if anyone else was interested, and hearing none Mike Jones made a motion to approve Bruce Metruck for the Vice-chair position, Brian Shanahan seconded. All were in favor. Randy Crissman said that Bruce Metruck will do the Executive Tracking Summary

5. FERC

- a. Issuances below.

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.1	Reply Brief	FA11-21-000	Reply Brief Of The North American Electric Reliability Corporation	9/10/12
	<u>Summary, Instructions, Dates =></u>	The disagreements between NERC and the Audit Staff continue to narrow in resolving minor differences, but have hardened with respect to the major differences.		
5.2	Filing	RM06-16-000	Filing for Approval of Errata Change to NERC Glossary of Terms	9/13/12
	<u>Summary, Instructions, Dates =></u>	On March 16, 2012, NERC submitted a filing that requested that the NERC Glossary of Terms be amended to modify the definition of "Interconnection Reliability Operating Limit (IROL)" by replacing the reference to "Cascading Outages" with "Cascading outages." NERC's uncontested filing is approved.		
5.3	Petition	RD12-4-000	Petition for Approval of Errata Changes to Seven Reliability Standards	9/17/12
	<u>Summary, Instructions, Dates =></u>	NERC's uncontested filing is approved.		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.4	Reply Comments	RM12-6-000, RM12-7-000	Reply Comments Of The North American Electric Reliability Corporation In Response To Notice Of Proposed Rulemaking	9/19/12
	<u>Summary, Instructions, Dates =></u>	NERC offers comments on the following: (1) the extent of FERC’s jurisdiction in connection with the scope of the BES Definition, (2) the exceptions process as set forth in the Rules of Procedure, and (3) the scope of Phase 2 of the BES Definition. In addition, several entities offer revised language to the BES Definition for consideration by FERC. As FERC has noted in prior instances, such comments should have been submitted during the standard development process and FERC should reject such comments		
5.5	Notice Of Proposed Rulemaking	RM12-12-000	Regional Reliability Standard PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	9/20/12
	<u>Summary, Instructions, Dates =></u>	FERC proposes to approve regional Reliability Standard PRC-006-NPCC-1, but comments on: (1) the technical basis for the 57.8 Hz maximum tripping limit for existing nuclear units established in Requirement R19; and (2) the time-frames for actions that result in changes to the NPCC UFLS program. Comments due 60 days after publication in the Federal Register.		
5.6	<u>Filing</u>	RM12-9-000	Filing Of The North American Electric Reliability Corporation In Support Of The Serc Reliability Corporation Response To The Notice Of Proposed Rulemaking On Regional Reliability Standard PRC-006-SERC-01	9/24/12
	<u>Summary, Instructions, Dates =></u>	On February 1, 2012, NERC submitted a petition seeking approval of regional Reliability Standard PRC-006-SERC-01– Automatic Underfrequency Load Shedding Requirements. On July 19, 2012, FERC issued a NOPR proposing to approve		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
		regional Reliability Standard PRC-006-SERC-01, but expressed concerns about a possible inconsistency between PRC-006-SERC-01 and the continent-wide PRC-006-1 — Automatic Underfrequency Load Shedding.		
5.7	Notice Of Proposed Rulemaking	RM12-12-000	Regional Reliability Standard PRC–006–NPCC–1— Automatic Underfrequency Load Shedding	9/26/12
	<u>Summary, Instructions, Dates =></u>	FERC proposes to approve regional Reliability Standard PRC–006–NPCC–1 (Automatic Underfrequency Load Shedding). NERC submitted the proposed regional Reliability Standard to FERC for approval. The proposed regional Reliability Standard applies to generator owners, planning coordinators, distribution providers, and transmission owners in the NPCC Region and is designed to ensure the development of an effective automatic UFLS program to preserve the security and integrity of the Bulk Power System during declining system frequency events, in coordination with the NERC continent wide UFLS Reliability Standard PRC–006–1.		
5.8	Notice Of Proposed Rulemaking	RM12-4-000	Revisions to Reliability Standard for Transmission Vegetation Management	10/18/12
	<u>Summary, Instructions, Dates =></u>	FERC proposes to approve FAC-003-2 (Transmission Vegetation Management). The proposed Standard would expand the applicability of the standard to include overhead transmission lines that are operated below 200 kV, if they are either an element of an IROL or an element of a Major WECC Transfer Path. In addition, the proposed Reliability Standard incorporates a new minimum annual vegetation inspection requirement, and incorporates new minimum vegetation clearance distances into the text of the standard.		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.9	Notice Of Proposed Rulemaking	RM12-22-000	Reliability Standards for Geomagnetic Disturbances	10/18/12
	<u>Summary, Instructions, Dates =></u>	FERC proposes to direct NERC to submit for approval Reliability Standards that address the impact of geomagnetic disturbances (GMD) on the reliable operation of the Bulk Power System. FERC proposes to do this in two stages. In the first stage, the FERC proposes to direct NERC to file one or more Reliability Standards that require owners and operators of the Bulk Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk Power System. In the second stage, FERC proposes to direct NERC to file one or more Reliability Standards that require owners and operators of the Bulk Power System to conduct initial and ongoing assessments of the potential impact of GMDs on Bulk-Power System equipment and the Bulk-Power System as a whole.		
5.10	Notice of Withdrawal	RM09-13-	Notice Of Withdrawal Of The North American Electric Reliability Corporation Of BAL-004-1 – Time Error Correction	10/24/12
	<u>Summary, Instructions, Dates =></u>	NERC submits this Notice of Withdrawal of its NERC’s March 11, 2009, Petition for Approval of the Time Error Correction Reliability Standard BAL-004-1. BAL-004-0 is currently effective and is unaltered by the submission of this Notice.		
5.11	Order Approving Amendments to the NERC/RFC Delegation Agreement	RR12-12-000	Amendments to Delegation Agreement with ReliabilityFirst Corporation	10/24/12
	<u>Summary, Instructions, Dates =></u>	On July 30, 2012, NERC submitted a filing that seeks approval of proposed amendments to NERC’s Delegation Agreement with ReliabilityFirst Corporation (RFC), including approval of amendments to RFC’s Bylaws and Reliability Standards Development Procedure.		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.12	Third Quarter 2012 Quarterly Report of the North American Electric Reliability Corporation on the Status of Development of Version 5 Critical Infrastructure Protection Reliability Standards	RM11-11-000	Third Quarter 2012 Quarterly Report of the North American Electric Reliability Corporation on the Status of Development of Version 5 Critical Infrastructure Protection Reliability Standards	10/31/12
	<u>Summary, Instructions, Dates =></u>	On April 19, 2012, FERC issued an order approving the Version 4 CIP Reliability Standards and imposing a March 31, 2013, deadline by which time NERC must file CIP Reliability Standards that are fully compliant with Order No. 706. FERC also required the submission of reports at the “beginning of each quarter” explaining whether NERC is “on track to meet the deadline and describe the status of its CIP standard development efforts.” The instant filing is submitted in compliance with this directive.		
5.13	Filing for Approval of Compliance Filing	RM11-20-002	Filing for Approval of Compliance Filing In Response to Order No. 763 on Automatic Underfrequency Load Shedding Reliability Standards	11/9/12
	<u>Summary, Instructions, Dates =></u>	On May 7, 2012, FERC issued Order No. 763 approving PRC-006-1 and EOP-003-2, that address underfrequency load shedding plans. Order No. 763 directed modifications to Reliability Standard PRC-006-1, Requirement R9, and to a Violation Risk Factor and Violation Severity Level associated with PRC-006-1. Order No. 763 directed NERC to make a compliance filing. On August 9, 2012, NERC submitted a compliance filing modifying the Violation Risk Factor and Violation Severity Level in compliance with Order No. 763. Additionally, NERC proposes in the compliance filing to modify PRC-006-1, Requirement R9 in accordance with Order No. 763, when a standard development project is next initiated for modifying PRC-006-1.		

<u>Item</u>	<u>NOPR, Petition, Final Rule, Other</u>	<u>Docket No.</u>	<u>Title</u>	<u>Posted</u>
5.14	Notice of Proposed Rulemaking	RM12-12-000	Comments Of The North American Electric Reliability Corporation In Response To Notice Of Proposed Rulemaking	11/26/12
	<u>Summary, Instructions, Dates =></u>	FERC seeks comment on: (1) the technical basis for the 57.8 Hz maximum tripping limit for existing nuclear units established in Requirement R19; and (2) the time-frames for actions that result in changes to the NPCC UFLS program. NERC supports the comments submitted by NPCC in this proceeding on the two issues addressed in the NOPR. NERC and NPCC assert that a region-wide and fully coordinated single set of UFLS requirements is of benefit to achieving an effective and efficient UFLS program. The requirements in the PRC-006-NPCC-1 standard are consistent with the PRC-006-1 NERC standard and support reliability. NERC respectfully requests that the Commission approve PRC-006-NPCC-1 and the associated violation risk factors, violation severity levels and effective dates.		

Item 5.1--Guy Zito discussed. This entry deals with budgetary items.

Item 5.2--Guy Zito mentioned that this was an errata filing.

Item 5.3--Guy Zito mentioned that this was an errata filing.

Item 5.4--Guy Zito reported that it is anticipated that the final order will be released in December. It will probably have directives, and compliance filings. The Application Guideline document is posted.

Item 5.5--Guy Zito discussed that this issuance regards NPCC's PRC-006-NPCC-1, and that there is an issue with compensatory load shedding. There is no mechanism for generators to secure compensatory load shedding. Mike Garton reported that that hasn't changed. Guy Zito does not expect a remand, but directives may be generated.

Item 5.6--Guy Zito reported that this is a SERC issue. There is a question about a conflict with the NERC Standard.

Item 5.7--This is in addition to Item 5.5 above.

Item 5.8--Guy Zito stated that this item deals with vegetation management. Clearances required are an open item.

Item 5.9--Guy Zito mentioned that this is a NOPR for geomagnetic disturbances. There will be two filings. The first is to address mitigation. The second filing will be more comprehensive. NERC is developing a standard. Howard Gugel said that an assessment is needed for areas where the geology doesn't make a system susceptible to GMDs. Kathleen Goodman commented that situational awareness is needed. The ISO-New England can make a white paper available. David Kiguel remarked that Hydro One and the IESO will be making comments. Ben Li reported that NERC is working on a SAR. David Kiguel remarked that

information is needed from transformer manufacturers. Kathleen Goodman said that procedures are needed to address the FERC order within 90 days. Howard Gugel recommended that the attendees read the NOPR and file comments. There was a Hydro-Quebec presentation on GMD scheduled for the afternoon.

Item 5-10--Guy Zito reported that field testing was done. Is time error correction still needed? Discussion ensued. FERC indicated to NERC that the Standard would be remanded. The NERC Board was asked to remand. Kathleen Goodman remarked that from a public interest perspective there is a possible health and safety issue. This should be a practice, not a standard. BAL-004-0 will still be in effect.

Item 5.11--Guy Zito reported on this being a change in the RFC Delegation Agreement.

Item 5.12--Guy Zito reported that Version 5 was approved by the NERC Board, and will be filed. When FERC approves, there will be an issue with the implementation of Versions 4 and 5. Greg Goodrich gave a presentation at yesterday's General Meeting. (Presentation posted on the [NPCC Website](#).) There is a question of whether or not entities can move from implementing Version 3 directly to Version 5, or will they have to honor Version 4. There is no intentional delay. It is just wanted to be sure that everything is covered.

Item 5.13--Guy Zito mentioned that this was an informational posting for revisions to R9.

Item 5.14--Guy Zito said that this NOPR was seeking comments on PRC-006-NPCC-1.

6. Posted NERC Projects (in Meeting Materials Package)

a. Cost Effective Analysis Process (CEAP). Refer to Item 1b in the Supplement Agenda for [Jon Wellinghoff statement](#).

Kathleen Goodman asked why the CEAP wasn't used for the GMD project. Guy Zito responded that because of the nature of the GMD project the use of the CEAP wasn't well received. Guy Zito will discuss with Howard Gugel what standard the CEAP may be applied to for trial. Are there any ideas? Possibly the standard on adding reclosers.

b. Standard Process Manual Revisions to Implement SPIG Recommendations.

Ben Li--the idea of dropping the VRFs and VSLs was rejected. Measures will also stay. RSAWs must stay within the scope of a standard. The CEAP will not be in the Standard Processes Manual. For now, the CEAP will be a stand alone document. Regarding the handling of "No" votes, at the Initial Ballot or Successive Ballot stages, "No" votes will be counted towards a quorum, but not in the vote count. For the final ballot, comments can't be submitted, so "No" votes will be counted. That will be the only instance. The Standard Drafting Team's conduct will be looked at. Comments will be considered from previous ballots. The waiver provision in Section 16 will be used to get out of a procedural issue.

Related discussion lead by Ben Li. The NERC Board of Trustees passed a resolution to ask for the Standards Committee to show its accountability for standards development at the Board of Trustees' February Meeting. Kathleen

Goodman asked what is the definition of accountability? Ben Li countered that the Standards Committee is accountable for standards' development on a timely basis. Guy Zito asked if technical discussions are to take place at the Standards Committee. Ben Li replied that the Standard Drafting Team has the technical expertise, so does it need to be discussed at the Standards Committee? The Standards Committee is supposed to look at the process. Its Charter will be revised. David Kiguel and Ben Li both mentioned that the RISC's existence has to be considered. There is the possibility that more committees will have to be formed. Guy Zito asked if there will be opportunities for the RSC's input, and Ben Li said yes. Guy Zito encouraged that the open process be used for this. Gerry Dunbar asked why the CEAP is not in the Standards Process. Guy Zito replied that the CEAP is a supplement. Howard Gugel commented that it also wasn't ready. David Kiguel asked how the Standard's Committee composition will be changed. Ben Li replied that it will be presented to the Board in February.

- c. Response to Passage of Critical Infrastructure Protection Version 5 Standards.
For information. Greg Campoli asked if entities can submit anything to support going to Version 5, thus avoiding having to go to Version 4. Guy Zito commented that a NOPR will likely be sent out. Something can be filed at that time.
- d. NERC server unavailable Dec. 1, 2012 for balloting, comment submission.
For information.

	<u>Project and Supporting Materials</u>	<u>Current and Pending Ballots</u>		<u>Join Ballot Pools</u>		<u>Posted for Comment</u>	
1.	<u>Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS</u>	Initial Ballot		10/22/12	11/20/12	10/22/12	12/5/12
		11/26/12	12/5/12				
2.	<u>Project 2013-02 - Paragraph 81</u>	Initial Ballot		10/25/12	11/23/12	10/25/12	12/10/12
		11/30/12	12/10/12				
3.	<u>Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE</u>	Initial Ballot		11/6/12	12/5/12	11/6/12	12/20/12
		12/11/12	12/20/12				
4.	<u>Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy</u>	----	----	----	----	11/9/12	12/10/12
5.	<u>Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC</u>	----	----	----	----	11/9/12	12/10/12
6.	<u>Project 2007-02 - Operating Personnel Communications Protocols</u>	Successive Ballot		----	----	11/14/12	12/13/12
		12/4/12	12/13/12			RSAW Comment Form Comments to be sent to RSAWfeedback@nerc.net	
		Non-binding Poll					
		12/4/12	12/13/12				
7.	<u>Project 2007-06 - System Protection Coordination</u>	Successive Ballot		----	----	11/16/12	12/17/12
		12/7/12	12/17/12				
		Non-binding Poll					

		12/7/12	12/7/12				
8.	Standard Processes Manual to Implement SPIG Revisions	Successive Ballot		----	----	11/21/12	12/20/12
		12/11/12	12/20/12				

Item 6-1Table--David Kiguel will send Lee Pedowicz comments.

Item 6-2Table--Guy Zito said that there will be one ballot for the entire package. If the vote is “No”, whatever the issue is must be specified. The Drafting Team will be meeting Dec. 20, 2012 to discuss the requirements. The only indication of a removed requirement in a Standard document will be that the requirement will have a strike through. It will be removed in its entirety in a future revision. There will also be a Phase 2. Phase 2 may be much broader in scope. Guy Zito would like to recommend a “Yes” vote. Ben Li to send comments to Lee Pedowicz.

Item 6-3Table--TFIST reviewed and had no comments. Any comments are to be sent to Guy Zito by Dec. 5, 2012 to Guy. Mike Garton commented that Dominion is in agreement with TFIST’s review.

Item 6-4Table--TFIST reviewed and had no comments. Any comments are to be sent to Guy Zito by Dec. 5, 2012.

Item 6-5Table--TFIST reviewed and had a response to Question 2. Guy Zito asked that any additional comments be sent to him by Dec. 5, 2012. Mike Garton mentioned that Dominion’s comments are almost identical to those of TFIST.

Item 6-6Table--Howard Gugel discussed the Standard. He commented that the redline is from the last version. Kathleen Goodman remarked that she thinks the Drafting Team is ignoring industry comments. Ben Li said this Standard is being viewed as a Zero Defect Standard. Guy Zito made a request for comments by Dec. 5, 2012. Kathleen Goodman will send out documentation.

Item 6-7Table--Guy Zito asked for comments.

Item 6-8Table--Discussed with Ben Li earlier in the Meeting under Item 6b.

7. Current NERC Drafting Team Nominations

a.				

8. NERC Meetings (in Meeting Materials Package)

- a. NPCC Governmental/Regulatory Affairs Advisory Group--Sylvain Clermont report on the Canadian Bulk electric System Exception Process.
Sylvain Clermont was not in attendance at the meeting to discuss.
- b. Standards Committee Meeting Nov. 8, 2012. Cold weather preparedness issue.
David Kiguel discussed. Ben Li reported that there is a Paragraph 81 Drafting Team vacancy. An approval posting for Paragraph 81 was given by the Executive Committee, with provisions.
- c. RISC Meeting--Dec. 17, 2012. Nominations for membership being considered until Dec. 17, 2012.
Guy Zito reported that nominations for issues to go before the RISC will be entertained. Ed Schwerdt asked Guy Zito to be the funnel for submitting items on behalf of NPCC.
- d. BES Phase 2 Meeting--Nov. 14-15, 2012.
Guy Zito discussed.
- e. Winter Preparation for Severe Cold Weather--Webinar Dec. 10, 2012.
 - 1. Lessons Learned--Southwest Cold Weather Event.
For information.

9. NERC Compliance Activity (in Meeting Materials Package)

a.

	<u>Draft CANs--Table</u>	<u>Posted</u>	<u>Comments Due</u>

10. NERC Items of Interest

- a. Reliability Assurance Initiative--Concept White Papers posted--Nov. 26, 2012.
Discussed at the RSC/CC Meeting Nov. 30, 2012.

Howard Gugel reported on NERC organizational changes. Mark Lauby now heads the Standards Section. There will be different groups--Paragraph 81, complete jobs in progress. Do projects warrant having a standard? Howard Gugel plans on attending RSC Meetings.

Ben Li commented that the Standards Committee will be looking for ways to not waste industry efforts.

11. NPCC Regional Standards, Directories and Related Items (in Meeting Materials Package)

- a. Status of PRC-002-NPCC-01 Disturbance Monitoring.
Guy Zito reported that he worked with Daren Verner to develop language to put in a RSAR that will be forthcoming to address the BES issue. Kathleen Goodman asked why cost effectiveness wasn't considered. Guy Zito replied that the CEAP was outside the process. The RSAR being developed will not mention cost or A-10. The objective of the Standard is to have adequate disturbance monitoring equipment installed on the system. Robert Pellegrini said that the Drafting Team never intended to have DFR at all 100kV stations. Kathleen Goodman commented that the clock has started on the Implementation Plan. Guy Zito mentioned that there is a possibility of having the Implementation Plan extended. Changes to the Implementation Plan would just have to go to the NPCC Board.
- b. Directory#1--TFCO Ad Hoc group reviewing Phase 2 criteria language in order to arrive at a consistent regional interpretation of the criteria.
Gerry Dunbar lead the discussion. He commented that there is a difference in the interpretation of Criteria between entities. This issue has been moved to a higher management level.
- c. Directory#5--TFCO addressed a number of key reserve issues that remained from the original approval of Directory #5 including wheeling radial contingencies outside the region. Full Members approved these revisions on October 11, 2012.
- d. Directory#7--SPS TFSP coordinated a comprehensive review of Directory #7 in order to establish Phase 2 Directory #7 requirements consistent with Directory #4 (BPS Protection Criteria). The CC also approved compliance requirements in order to maintain existing protection criteria while encouraging innovation and creativity in protection design. Directory #7 posted to the Open Process through Nov. 12, 2012.
Gerry Dunbar lead the discussion.
- e. Directory #12-- the TFSS posted Directory #12 to the Open Process for 45 days concluded on October 26th, 2012. The TFSS has proposed changes to Directory #12 that will synchronize the UFLS program tolerance bands between Directory #12 and the UFLS Regional Standard and allow regional entities to implement a program that is consistent with the SS-38 design recommendations as part of the ongoing six year UFLS Implementation Plan.
Gerry Dunbar remarked that TFSS will respond to all comments.
- f. Directory Interpretations--TFSP and TFCO have each completed an interpretation (on Directory #3 and Directory #8 respectively). TFSP has two interpretations pending (Directory #3).

Roger Champagne commented that the Directories should be reformatted to be consistent with Standards. Duplicative requirements must be removed. Ben Li mentioned that he can't find the responses to comments on the Directories. Gerry Dunbar pointed out that there is an area on the NPCC Website to view comments. David Kiguel asked if Criteria are still needed in light of the expansion of NERC Standards. Guy Zito replied that Criteria contain assessments that are too prescriptive to be included in the Standards.

12. Joint Meeting with the Compliance Committee

a. Roundtable.

Guy Zito gave the CC a list of items for discussion. The joint RSC/CC Meeting was moved to 8:00 a.m. tomorrow.

Meeting called to order at 08:05 a.m. by Stan Kopman.

Stan Kopman discussed the joint RSC/CC Meetings. Guy Zito remarked that he felt that one meeting was adequate. Teleconferences can always be held. Mike Garton commented that the overlap of RSC and CC Meetings during the period of the NPCC General Meeting is a problem.

Guy Zito lead a discussion of PRC-002-NPCC-01. TFSP was concerned about its applicability because of the change in the BES definition. Guy Zito worked with TFSP to craft language for a RSAR to ensure that there will be adequate DME resources to monitor the BES. The Implementation Plan will be looked at, but may have to be refiled. A RSAR is in progress. David Kiguel also said that a new RSAR will be developed, and that the RSARs already developed were not accepted. Will have to accommodate the NERC process. Peter Yost commented that the Standard is adequate as written. David Kiguel commented that the Standard was written for A-10 facilities. The Drafting Team wrote the Standard to that. Guy Zito reiterated that the Standard has to be reviewed to ensure that adequate disturbance monitoring equipment is called for. There is the possibility that the Standard will be left as is. Guy Zito said that the cost effectiveness procedure will be utilized. Peter Yost asked for a timeline for getting the Standard to FERC if the RSAR is approved to move forward. Guy Zito said that it will probably take a year. Jonathan Appelbaum remarked that there is no continent-wide disturbance monitoring standard. If its development gets underway, it may affect PRC-002-NPCC-01. Kathleen Goodman commented that FERC and NERC will be challenged by the public on the cost issue. It may not be too cautious to bring the cost issue to a head.

Guy Zito reported that VRFs and VSLs are not going to be going away, and the RSC hoped that the CC will take more ownership of the compliance elements of standards. The RSC would prefer the Compliance look at VRFs and VSLs. The CC should get involved with building consensus. When a consensus on comments is not reached, Guy Zito said that he sends out an E-mail describing the concerns. Jonathan Appelbaum commented that he provided comments to Lee Pedowicz when he knows they are out there. He wants to provide comments. Stan Kopman said for CC to provide input to the compliance aspects of a standard has been considered in the past. Individual entities can always submit comments. Lee Pedowicz will copy the CC when soliciting for comments. Guy Zito remarked that the audit aspect of a standard must be looked at. Sal Buffamante said that the content of a standard must be reviewed from a compliance perspective. Guy Zito said that the CC should look at a standard from an audit level.

Guy Zito discussed the Reliability Assurance Initiative. Stan Kopman spoke about the Compliance Enforcement Initiative (CEI). It is an attempt to use the

FFT for enforcement. It clarifies the risk-based approach to compliance, and also standards development. This will be the basis for a filing. Move towards a risk-based model. As documents are developed they will be posted for comments. Sal Buffamante said that this brings everything together that FERC and NERC have discussed, and will require more industry resources. Must be aware of the implications. This will not present a big change for NPCC. Stan Kopman commented that the principles will probably spill over to the standards process. Sal Buffamante commented that NPCC has never used zero tolerance, and that NPCC has been an example for the rest of the Regions.

Stan Kopman initiated a discussion of PRC-005, Directory #3. Jonathan Appelbaum remarked that there is a disconnect between testing intervals. Is Directory #3 needed? Is A-15 needed? Gerry Dunbar commented that TFSP has Directory #3 for review. However, it is not on their plan. Guy Zito said that he and Gerry Dunbar will work with TFSP to review and ensure that there is no duplication. Peter Yost asked for an example of where Directory #3 is less restrictive. It is to be looked at. Gerry Dunbar expressed his concern about the Task Forces' review of Directories. Brian Evans-Mongee said that April 1, 2013 the definition of protection system will be changing. Guy Zito said that Gerry Dunbar and the NPCC Staff will be reviewing Directories to see what revisions are needed.

Stan Kopman said that regarding the CCEP, the criteria are being looked at to be expanded. Inclusion of resource adequacy is an example. Should be included in the 2014 Implementation Plan.

The meeting was adjourned at 09:37.

13. Other Items of Interest

- a. Sebastian Guillon of Hydro-Quebec Trans-Energie gave a presentation on Hydro-Quebec TransEnergie - System Upgrades Related to Geomagnetic Disturbance. TFCO joined the RSC Meeting for the presentation.

14. Future NPCC Meetings

Proposed RSC 2013 Meeting Dates (possible locations)

Feb. 20-21, 2013--NextEra Offices--Florida
April 10-11, 2013--New York--NPCC Offices
June 12-13, 2013--Saratoga, New York Note: Date changed after the meeting to June 19-20, 2012
August 21-22, 2013--Toronto
Oct. 9-10, 2013--Montreal
Dec. 5-6, 2013 (General Meeting Dec. 4, 2013)-- Boston

2012 RSC Conference Call Schedule

(call 719-785-1707, Guest Code 8287#)

December 14, 2012
December 28, 2012

BOD 2013 Meeting Dates

January 29, 2013
January 30, 2013
March 12, 2013 –BES Implementation Teleconference
April 30, 2013 – Teleconference
June 25, 2013
August 6, 2013 – Teleconference
September 10, 2013
October 29, 2013 – Teleconference
December 4, 2013

RCC, CC, and Task Force Meeting Dates--2012/2013

RCC	
CC	11/29-30 (Montreal, Joint with RSC)
TFSS	
TFCP	
TFCO	November 29 2013: Jan. 17-18, March 20-21, May 15-16, August 28-29, Oct. 17-18, Dec. 5-6
TFIST	
TFSP	

A motion was made to adjourn by Mike Jones at 15:42. Seconded by David Kiguel. The Meeting was adjourned.

The joint RSC/CC Meeting was adjourned at 09:37 (see Item 12 above).

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, Andrianne S. Payson at 212-335-4765.

NPCC Reps on NERC Standards Drafting Teams						
Project No.	Project Title	DT Type	NPCC Representatives	Company	Telephone	E-mail Address
2006-02	Assess Transmission Future Needs & Develop Transmission Plans	Standard	Dana Walters	New York Independent System Operator	518-356-8582	dwalters@nyiso.com
2006-06	Reliability Coordination	Standard	Earl Barber	National Grid	315-428-5532	earl.barber@us.ngrid.com
2007-02	Operating Personnel Communications Protocols	Standard	Tom Irvine	Hydro One Networks	705-792-3004	tom.irvine@hydroone.com
2007-03	Real Time Operations	Standard				
2007-06	System Protection Coordination	Standard	David Cirka	National Grid	781-907-3240	david.cirka@us.ngrid.com
2007-07	Vegetation Management	Standard	Orville Cocking	Con Edison	917-789-6885	cockingo@coned.com
2007-07	Vegetation Management	Standard	Dave Morrell	New York State Dept of Public Svc	518-486-7322	david_morrell@dps.state.ny.us
2007-09	Generator Verification	Standard				
2007-12	Frequency Response	Standard	Mike Potishnak	ISO-NE	413-535-4308	mpotishnak@iso-ne.com
2007-17	Protection System Maintenance & Testing	Standard				
N/A	CIP Interpretations	Interpretation	Mark Engels	Dominion	804-775-5263	mark.engels@dom.com
N/A	CIP Interpretations	Interpretation	David Dunn	IESO	905-855-6286	david.dunn@ieso.ca
N/A	CIP Interpretations	Interpretation	Summer Esquerre	NextEra Energy	561-691-2643	summer.esquerre@nexteraenergy.com
2008-06	Cyber Security for Order 706	Standard	John Lim	Con Edison	212-460-2712	limj@coned.com
2008-06	Cyber Security for Order 706	Standard	Robert Antonishen	Ontario Power Generation	905-262-2674	rob.antonishen@opg.com
2008-06	Cyber Security for Order 706	Standard	Rene Bourassa	Hydro Quebec - TransEnergie	819-694-2507	bourassa.rene@hydro.qc.ca
2008-06	Cyber Security for Order 706	Standard	Thomas Stevenson	Constellation Energy	410-787-5260	thomas.w.stevenson@constellation.com
2009-01	Disturbance and Sabotage Reporting	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2009-01	Disturbance and Sabotage Reporting	Standard	Michelle Draxton	Constellation Energy Group	410-474-2993	Michelle.I.draxton@constellation.com
2009-22	Interpretation of COM-02-2	Interpretation	Tom Irvine	Hydro One Networks	705-792-3004	tom.irvine@hydroone.com
2010-05-1	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One Networks	647-328-7068	paul.difilippo@hydroone.com
2010-07	Generator Requirements at the Transmission Interface	SAR	Louis Slade	Dominion	804-819-2871	louis.slade@dom.com
2010-13.2	Phase 2 of Relay Loadability: Generation	Standard	Steven Hataway	Florida Power & Light		
2010-13.2	Phase 2 of Relay Loadability: Generation	Standard	Ziaodong Sun	Ontario Power Generation		
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard	Michael Potishnak	ISO-New England	413-535-4308	mpotishnak@iso-ne.com
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard	Guy Quintin	Hydro Quebec - TransEnergie	514-289-2211 X3150	Quintin.Guy@hydro.qc.ca
2010-17	Definition of Bulk Electric System	Standard	Jennifer Dering	NYP&A	914-287-3179	Jennifer.Dering@nypa.gov
2010-17	Definition of Bulk Electric System	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2010-17	Definition of Bulk Electric System	Standard	Phil Fedora	NPCC	212-840-4909	pfedora@npcc.org
2010-17	Definition of Bulk Electric System	Standard	Ajay Garg	Hydro One Networks	416.345.5420	ajay.garg@HydroOne.com
2010-17	Definition of Bulk Electric System	Standard	Jennifer T. Sterling	Exelon	630-437-2764	jennifer.sterling@exeloncorp.com
2010-17	Definition of Bulk Electric System - Rules of Procedure	Standard	Martin Boisvert	Hydro Quebec - TransEnergie	514-879-4100	boisvert.martin@hydro.qc.ca
2010-17	Definition of Bulk Electric System - Rules of Procedure	Standard	Ajay Garg	Hydro One Networks	416.345.5420	ajay.garg@HydroOne.com
2013-02	Paragraph 81	Standard	Guy Zito	NPCC	212-840-1070	gzito@npcc.org
2013-02	Paragraph 81	Standard	David Kiguel	Hydro One Networks		david.kiguel@hydroone.com
Source = NERC Standard Drafting Team Rosters - January 2013						
Change Control: Changes since August 2012:						
Project 2007-03 Real Time Operations - Added back onto the report. Phil Lavallee, National Grid, was previously listed as the representative.						
Project 2007-09 Generator Verification - Removed Vladimir Stanisc from the NPCC representative list. Vladimir Stanisc now works for BC Hydro, not Ontario Power Generation.						

Revised: 2/4/2013

Tab Name	Last Revised	Summary of Changes
<u>NERC RS Exec Tracking Summary</u>	2/4/2013	Interpretation 2012-INT-05 – Interpretation of CIP-002-3 - recirculation ballot until 1/23/13 Project 2013-02 - Paragraph 81 - recirculation ballot until 1/17/13 Project 2007-09 - Generator Verification - PRC-024-1 - successive ballot until 1/11/13; industry "No" Project 2010-11 - TPL Table 1, Footnote B - successive ballot; industry "No"
<u>NERC CANS</u>	8/6/2012	CAN-0011, PRC-005 R2: Interval Start Date for New Equipment - Revision Posted 6/15/12 CAN-0012, Completion of Periodic Activity Requirements During Implementation Plan - Revision Posted 6/15/12
<u>NERC RSAWs</u>	12/28/2012	CIP-001-2a RSAW Issued 10/13/12 COM-003-1 RSAW posted for comment thru 12/13/12 EOP-001-2b RSAW Issued 10/13/12 EOP-003-2 RSAW Issued 10/13/12 EOP-005-2 RSAW Issued 10/13/12 EOP-006-2 RSAW Issued 10/13/12 EOP-008-1 RSAW Issued 10/13/12 FAC-008-3 RSAW Issued 10/13/12 FAC-013-2 RSAW Issued 10/13/12 IRO-014-1 RSAW Issued 10/13/12 PRC-023-2 RSAW Issued 11/15/12
<u>NPCC RRS Tracking Summary</u>	12/11/2012	FERC issued a NOPR on PRC-006-NPCC-01, Automatic Underfrequency Load Shedding Program on Sept. 20, 2012, and sought comments on Nov. 26, 2012. NERC provided reply comments.
<u>NPCC Doc Tracking Summary</u>	7/16/2012	B-01: Draft Revised NPCC Guide for the Application of Autorelosing to the Bulk Power System - Posted to Open Process A-07 (retired), Revise Critical Component Definition (Glossary of Terms) - retirement date corrected.
<u>NPCC Directory Tracking Summary</u>	2/4/2013	Directory#12--Automatic UFLS Program Requirements posted for comment in the NPCC Open Process through March 14, 2013. Clarification of the criteria surrounding Section 5.6.2 of Directory#3 Maintenance Criteria for Bulk Power System Protection (completed Dec. 20, 2012). Clarification of the criteria surrounding Section 5.7.1 of Directory#3 Maintenance Criteria for Bulk Power System Protection (completed Dec. 20, 2012).

NERC Reliability Standards Executive Tracking Summary

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
											DATA REQUEST PUBLISHED - Comments due 8/30/12 On April 19, 2012 FERC issued Order 762 remanding TPL-002-2b and FERC proposed to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
1	Project 2006-02 — Assess Transmission and Future Needs	High	TPL-001-2	Yes 3rd (Thru 3/16/07)	Yes 5th (Formal Thru 5/31/11)	Yes (Recirculation Thru 7/22/11)	Yes (7/22/11)	Yes (8/4/11)	Yes (10/19/11)			Under Development
2	Project 2007-07 — Vegetation Management	Normal	FAC-003-2	Yes 3rd (Thru 7/17/07)	Yes 5th (Thru 2/28/11)	Yes 6th (Recirculation Thru 10/13/11)	Yes (10/13/11)	Yes (11/3/11)	Yes (12/21/11)			Under Development
3	Project 2008-14 — Cyber Security Violation Severity Levels	No	CIP family of standards	Yes 2nd (Thru 04/20/09)	Yes 1st (Thru 04/20/09)	Yes (Recirc Thru 7/16/09)	Yes (7/16/09)	Date?	Date?			Pending Regulatory Approval
4	Project 2009-26 — Interpretation of CIP-004-1 by WECC	No	CIP-004-1, R2, R3 and R4	x	Yes (Thru 3/23/12)	Yes (Recirculation Thru 4/30/12)	Yes (4/30/12)	Yes (5/9/12)	Yes (8/1/12)			Pending Regulatory Approval
5	Project 2010-07 — Generator Requirements at the Transmission Interface	High	FAC-001-1, FAC-003-3, FAC-003-X, PRC-004-2	Yes 1st (Thru 3/15/10)	Yes 3rd (45 Day Formal Thru 11/18/11)	Yes (Recirculation Thru 12/23/11)	Yes (12/23/11)	Yes (2/9/12)	Yes (7/30/12)			Pending Regulatory Approval
6	Project 2010-07 — Generator Requirements at the Transmission Interface	High	FAC-003-3, FAC-003-X, PRC-005-1.1b	Yes 1st (Thru 3/15/10)	Yes (30 Day Formal Thru 4/9/12)	Yes (Recirculation Thru 5/3/12)	Yes (5/3/12)	Yes (5/9/12)	Yes (7/30/12)			Pending Regulatory Approval
7	Project 2010-17 — Definition of Bulk Electric System	High	NERC Glossary Of Terms	Yes 1st (Thru 1/21/11)	- Yes 3rd (Definition Thru 10/10/11) - Yes 2nd (ROP & Tech Principles Thru 10/10/11)	Yes (Recirc Thru 11/21/11)	Yes 11/21/11	Yes (1/18/12)	Yes (1/25/12)			
8	Project 2010-INT-05 CIP-002-1 Requirement R3 for Duke Energy	No	CIP-002-4a, R3	x	Yes (Thru 3/23/12)	Yes (Recirculation Thru 4/30/12)	Yes (4/30/12)	Yes (5/9/12)	Yes (8/1/12)			Pending Regulatory Approval
9	Project 2011-INT-01 Interpretation of MOD-028 for FPL	No	MOD-028-2	Yes 1st (Thru 11/16/11)	Yes 1st (Thru 11/16/11)	Yes (Recirculation Thru 12/22/11)	Yes (12/22/11)	Yes (2/9/12)	Yes (8/24/12)			Under Development
10	Project 2006-06 — Reliability Coordination	Normal	IRO-002-3, IRO-005-4, IRO-014-2 COM-001-2, COM-002-3, IRO-001-3 and IRO-014-2	Yes 3rd "Supp" (Thru 9/3/10)	Yes (Thru 7/6/12) COM-001-2 COM-002-3 IRO-001-3	Yes (Recirculation Thru 9/17/12) COM-001-2 (Approved 75.01%) Yes (Recirculation Thru 7/6/12) COM-002-3 IRO-001-3	COM-001-2 Yes (9/17/12) COM-002-3 IRO-001-3 Yes (7/6/12) IRO-002-3 IRO-005-4 IRO-014-2 Yes (7/25/11)	COM-001-2, COM-002-3 Yes (11/7/12) Yes (8/16/12) IRO-002-3 IRO-005-4 IRO-014-2 Yes (8/4/11)			Pending Regulatory Approval	
11	Project 2007-03 — Real-time Operations	High	TOP-001-2, TOP-002-3, TOP-003-2 and PER-001-2	Yes 2nd (Thru 9/07/07)	Yes (Thru 4/20/12)	Yes (Successive Thru 4/20/12)	Update 5/6/12	Update 5/9/12				Under Development
12	Project 2008-10 — Interpretation of CIP-006-1 R1.1 by Progress Energy	No	CIP-006, R1.1	x	Yes (thru 11/21/11)	Yes (Recirculation Thru 12/19/11)	Yes 12/19/11	Yes (2/9/12)				Under Development
13	Project 2009-01 — Disturbance and Sabotage Reporting	High	EOP-004-2	Yes 1st (Thru 5/21/09)	Yes (Thru 9/27/12)	Yes (Recirculation Thru 11/5/12)	Yes (11/5/12)	Yes (11/7/12)				Pending Regulatory Approval
14	Project 2009-19 — Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group	No	BAL-002-0 R4 and R5	x	Yes - Draft #2 (Thru 9/4/12)	Yes (Recirculation Thru 10/8/12)	Yes (10/8/12)	Yes (11/7/12)				Pending Regulatory Approval
15	Project 2009-22 — Interpretation of COM-002-2 R2 by the IRC	High - Interp.	COM-002-2	x	2nd (45 day Formal thru 11/17/11)	Yes (Recirculation Thru 12/23/11)	Yes (12/23/11)	Yes (2/9/12)			Project 2009-22 (COM-002-2), which applies to real-time emergency communications, was approved by NERC BOT with an amendment that calls for the prioritization of a revised standard and a best practices memorandum shared with industry.	Under Development
16	Project 2010-07 — Generator Requirements at the Transmission Interface	High	PRC-004-2	Yes 1st (Thru 3/15/10)	Yes 1st (45 Day Formal Thru 11/18/11)	Yes (Recirculation Thru 12/23/11)	Yes (12/23/11)	Yes (2/9/12)			PRC-004-2.1a NERC BOT Approved	Under Development
17	Project 2010-07 — Generator Requirements at the Transmission Interface	High	PRC-005-1.1a	x	Yes (45 Day Formal Thru 4/16/12)	Yes (Recirculation Thru 5/3/12)	Yes (5/3/12)	Yes (5/9/12)				
18	Project 2010-09 — Cyber Security Order 706B — Nuclear Plant Implementation Plan	No	Various CIP Standards	Yes 1st (Thru 3/15/10)	Yes 1st (Thru 3/15/10)	Yes (Recirc Thru 7/2/10)	Yes (7/2/10)	Yes (8/5/10)				Pending Regulatory Filing
19	Project 2010-INT-01 Interpretation of TOP-006-2 R1.2 and R3 for FMPP	No	TOP-006-3, R1.2 and R3	NA	Yes - Draft #1 (Thru 7/30/12)	Yes - (Recirculation Thru 9/21/12) Approved 87.5%	9/21/2012	Yes (11/7/12)				Pending Regulatory Approval
20	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation	No	VAR-002-2b, R2	x	Yes (Thru 6/27/12)	Yes (Recirculation Thru 7/27/12)	Yes (7/27/12)	Yes (8/16/12)			"Rapid Revision"	Pending Regulatory Approval
21	Project 2007-17 — Protection System Maintenance & Testing RE-INITIATED	High	PRC-005-2	Yes 1st (Thru 9/28/11)	Yes (Thru 8/27/12)	Yes (Recirculation Thru 10/24/12)	Yes (10/24/12)				The standard will be presented to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities	Under Development
22	Project 2008-06 — Cyber Security — Order 706 -- CIP Version 5 Standards	High	CIP-002-5 thru CIP-009-5, CIP-010-1 and CIP-011-1	x	Yes (Thru 11/5/12)	Yes (Recirculation Thru 11/5/12)	Yes (11/5/12)				Next Steps: The standards will be presented to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.	Industry Approved
23	Project 2009-20 — Interpretation of BAL-003-0 R2 and R5 by Energy Mark, Inc.	No	BAL-003-0.1b	x	x	Yes (Recirc Thru 2/26/10)	Yes (2/26/10)					Under Development
24	Project 2007-02 — Operating Personnel Communications Protocols	High	COM-003-1 and COM-002-2	Yes 2nd (Thru 5/2/07)	x	Yes (Successive Thru 12/13/12)	No (12/13/12)				Posted with RSAW- see RSAW Tab	Under Development
25	Project 2007-06 — System Protection Coordination	High	PRC-027-1 Update	Yes 1st (Thru 7/10/07)	Yes (Thru 12/17/12)	Yes (Successive Thru 12/17/12)	No (12/17/12)					Under Development

NERC Reliability Standards Executive Tracking Summary

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
26	Project 2007-09 — Generator Verification	High	MOD-024-2, MOD-025-2, MOD-026-1, MOD-027-1, PRC-019-1 and PRC-024-1	Yes 1st (Thru 5/21/07)	PRC-024-1 Yes (Thru 1/11/13)	Recirculation Thru 12/21/12) MOD-025-2, MOD-026-1, MOD-027-1, PRC-019-1 ;Successive Ballot PRC-024-1 thru 1/11/13	Yes (Recirc Ballot 12/21/12) No (Successive Ballot 1/11/13)					Under Development
27	Project 2007-12 — Frequency Response	High	BAL-003-1	Yes 3rd (Thru 3/09/07)	Yes 30 day Formal (thru 11/5/12)	Recirculation ballot thru 12/21/12	Yes (12/21/12)				Next Steps: The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.	Under Development
28	Project 2009-24 — Interpretation of EOP-005-1 R7 by FMPA	No	EOP-005-1, R7	x	x	Yes 1st (Initial Thru 1/15/10)					Balloting Deferred per Standards Committee	Under Development
29	Project 2010-05.1 — Protection Systems: Phase 1 (Misoperations)	High	PRC-004-3	Yes 1st (Informal Thru 7/11/11)	Yes (Draft #2 Thru 9/7/12)	Yes (Initial Thru 9/7/12) - Failed					"1." refers to Phase 1 of the Project	
30	Project 2010-11 — TPL Table 1 Order	No	TPL-001-2a, TPL-001-3, TPL-002-1c	Yes 1st (Thru 5/26/10)	Yes - Formal (Thru 1/11/13)	Successive ballot 1/2/13 thru 1/11/13	No (1/11/13)				Draft #7 of TPL-001-2a and Draft #6 of TPL-002-1c posted for combined formal comment period and initial ballot On April 19, 2012 FERC issued Order 762 remanding TPL-002-2b and FERC proposed to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	Under Development
31	Project 2012-08.1 — Phase 1 of Glossary Updates: Statutory Definitions	No	NERC Glossary Of Terms	For Comment (Thru 8/2/12)	Yes (Thru 8/2/12)	Yes (Initial Thru 8/2/12)						
32	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	No	TPL-003 and TPL-004	NA	Yes - (Thru 12/5/12)	Yes (Initial Thru 12/5/12)	Yes (12/5/12)					
33	Project 2012-INT-05 – Interpretation of CIP-002-3 for OGE	No	CIP-002	NA	Yes (Thru 12/20/12)	Yes (Initial Thru 12/20/12) Recirc Ballot thru 1/23/13	Yes (12/20/12)					Under Development
34	Project 2013-02 — Paragraph 81	No		Draft for Comment (Thru 9/4/12)	Yes (Thru 12/10/12)	Yes (Initial Thru 12/10/12) Recirc Ballot thru 1/17/13	Yes (12/10/12)				The purpose of the project is to retire or modify FERC-approved Reliability Standard requirements that as FERC noted, "provide little protection to the reliable operations of the BES", are redundant or unnecessary, or to retire or modify a FERC-approved Reliability Standard requirement to increase the efficiency of the ERO's compliance programs.	Under Development
35	Interpretation 2012-INT-04 CIP-007-3 for ITC	No	CIP-007-3	NA	Yes (Thru 12/10/12)							
36	Interpretation 2012-INT-06 CIP-003-3 for Consumers Energy	No	CIP-003-3	NA	Yes (Thru 12/10/12)							
37	Project 2007-11 — Disturbance Monitoring	No	PRC-002-1 and PRC-018-1	Yes 1st (Thru 4/20/07)	Yes 1st (Thru 3/18/09)							Under Development
38	Project 2008-12 — Coordinate Interchange Standards	No	INT-004-, INT-006-4, INT-009-2, INT-010-2 and INT-011-1	Yes 1st (Thru 7/31/08)	Yes 1st (Thru 12/11/09)							Under Development
39	Project 2009-02 — Real-time Reliability Monitoring and Analysis Capabilities	No	"New"	Yes 2nd (Thru 2/18/10)	Yes 1st (Informal Thru 4/4/11)						Concept White Paper posted for informal comment period	Under Development
40	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	No	PRC-025-1	x	Yes 30 day formal (thru 11/5/12)						- "2." refers to Phase 2 of the Project - 2/15/12 - FERC has granted NERC a one-year extension of time to and including September 30, 2013 to complete the Project pursuant to the Commission's Order No. 733. [Docket No. RM08-13-001]	
41	Project 2010-14.1 — Phase 1 of Balancing Authority Reliability-based Control: Reserves	No	BAL-001-1, BAL-002-2, BAL-012-1, BAL-013-1	NA	Initial Ballot 1/4/13 thru 1/14/13	Yes (Initial 1/4/13 thru 1/14/13)					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	Under Development
42	Project 2010-16 — Definition of System Operator	No	NERC Glossary Of Terms	Yes 1st (Thru 12/3/10)	Yes 1st (Thru 12/3/10)							Under Development
43	Project 2010-17 — Definition of Bulk Electric System - Phase 2	High	NERC Glossary Of Terms	For Comment (Thru 2/3/12)	Yes - Informal (Guidance Document Thru 11/5/12)							Under Development
44	Project 2008-01 — Voltage and Reactive planning and control	No	VAR-001 and VAR-002	Yes 2nd (Thru 3/26/10)								Under Development
45	Project 2008-02 — Undervoltage Load Shedding	No	PRC-010-0 and PRC-022-1	Yes 1st (Thru 02/19/10)							June 2010 SC meeting - Project deferred until Higher Priority projects are completed	Project Deferred
46	Project 2009-03 — Emergency Operations	No	EOP-001, EOP-002, EOP-003 and IRO-001	Yes 1st (Thru 1/15/10)								Under Development
47	Project 2009-05 — Resource Adequacy Assessments	No	"New"	Yes 2nd (Thru 3/30/06)								Under Development
48	Project 2009-07 — Reliability of Protection Systems	No	"New"	Yes 1st (Thru 2/18/09)							Pending prioritization - may be postponed	Under Development
49	Project 2010-08 — Functional Model Glossary Revisions	No		Yes 1st (Thru 2/22/10)							June 2010 SC meeting - Project deferred until Higher Priority projects are completed	Project Deferred

NERC Reliability Standards Executive Tracking Summary

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
50	Project 2013-01 — Cold Weather Preparedness		"TBD"	Draft for Comment (Thru 10/24/12)								
51	Project 2009-04 — Phasor Measurement Units	No									2/15/12 - FERC has granted NERC a two-year extension of time to and including September 30, 2014 to complete the Project pursuant to the Commission's Order No. 742. [Docket No. RM09-25-000]	Project has not started
52	Project 2010-01 — Support Personnel Training	No										Project has not started
53	Project 2010-02 — Connecting New Facilities to the Grid	No										Project has not started
54	Project 2010-03 — Modeling Data	No										Project has not started
55	Project 2010-04 — Demand Data	No										Project has not started
56	Project 2010-06 — Results-based Reliability Standards	No	Results-based Reliability Standards Transition Plan								Transition Plan posted 7/26/10	
57	Project 2010-INT-02 Interpretation of TOP-003-1 R2 for FMPP	No	TOP-003-1, R2								Requester has been contacted to see if a CAN would satisfy their concerns until the standard is revised - awaiting response	On Hold
58	Project 2010-INT-03 Interpretation of TOP-002-2a R2, R8, and R19 for FMPP	No	TOP-002-2a, R2, R8 and R19								Requester has been contacted to see if a CAN would satisfy their concerns until the standard is revised - awaiting response	On Hold
59	Project 2012-01 Equipment Monitoring and Diagnostic Devices	No	FUTURE									
60	Project 2012-02 Physical Protection	No	FUTURE									
61	Pre-2006 — Operate Within Interconnection Reliability Operating Limits	No	IRO-008-1, IRO-009-1 and IRO-010-1a	Yes 2nd (Thru 9/23/02)	Yes 9th (Thru 4/25/08)	Yes 1st (Recirc Thru 8/21/08)	Yes (8/21/08)	Yes (10/17/08)	Yes (12/31/09)	Yes (3/17/11)	- Order on Rehearing published in Federal Register on July 19, 2011 - Rule published in Federal Register on March 23, 2011	Completed
62	Project 2006-01 — System Personnel Training	No	PER-004-2 and PER-005-1	Yes 2nd (Thru 3/20/06)	Yes 4th (Thru 7/17/08)	Yes 5th (Recirc Thru 12/22/08)	Yes (12/22/08)	Yes (04/01/09)	Yes (9/30/09)	Yes (11/18/10)		Completed
63	Project 2006-03 — System Restoration and Blackstart	No	EOP-001-1, EOP-005-2 and EOP-006-2	Yes 2nd (Thru 3/09/07)	Yes 4 th (Thru 11/18/08)	Yes 5th (Recirc Thru 5/18/09)	Yes (5/18/09)	Yes (8/5/09)	Yes (12/31/09)	Yes (3/17/11)	- Order on Rehearing published in Federal Register on July 19, 2011 (Effective Std EOP-001-2) - Rule published in Federal Register on March 23, 2011	Completed
64	Project 2006-04 — Backup Facilities	No	EOP-008-1	Yes 2nd (Thru 3/16/07)	Yes 5th (Thru 3/8/10)	Yes 7th (Recirc Thru 7/26/10)	Yes (7/26/10)	Yes (8/5/010)	Yes (2/11/11)	Yes (4/21/11)	Posted in Federal Register on 4/28/11	Completed
65	Project 2006-08 — Transmission Loading Relief	No	IRO-006-5 and IRO-006-East-1	Yes (For DT Nomination 1/12/07)	Yes 4th (Thru 11/30/09)	Yes 6th (Recirc Thru 8/30/10)	Yes (8/30/10)	Yes (11/4/10)	Yes (1/13/11)	Yes (4/21/11)		Completed
66	Project 2007-01 — Underfrequency Load Shedding	No	EOP-003-1 and PRC-006-1	Yes 3rd (Thru 3/29/07)	Yes 3rd (Thru 7/16/10)	Yes 6th (Recirc Thru 10/28/10)	Yes (10/28/10)	Yes (11/4/10)	Yes (3/31/11)	Yes (5/7/12)		Completed
67	Project 2007-04 — Certifying System Operators	Normal	PER-003-1	Yes 2nd (Thru 1/31/08)	Yes 1st (Thru 11/20/09)	Yes 3rd (Recirc Thru 12/13/10)	Yes (12/31/10)	Yes (2/17/11)	Yes (4/29/11)	Yes (9/15/11)		Completed
68	Project 2007-05 — Balancing Authority Controls	No	NA	NA	NA	NA	NA	NA	NA	NA	As of July 28, 2010 this project has been merged with Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control	NA
69	Project 2007-17 — Protection System Maintenance & Testing	High	PRC-005-2	Yes 1st (Thru 7/10/07)	Yes 4th (30 day formal Thru 5/12/11)	Yes 8th (Recirculation Thru 6/30/11)	Failed to reach ballot pool aproval	NA	NA	NA	After PRC-005-2 failed to reach ballot pool approval in the recirculation ballot that ended on 6/30/11, the drafting team revised the standard. The Standards Committee authorized re-initiating the project with a posting of the SAR and revised standard for a 45-day comment period, with an initial ballot of the standard conducted during the last 10 days of the comment period.	Re-initiated
70	Project 2007-18 — Reliability-based Control	No	NA	NA	NA	NA	NA	NA	NA	NA	As of July 28, 2010 this project has been merged with Project 2007-18 - Reliability-based Controls and is now Project 2010-14 - Balancing Authority Reliability-based Control	NA
71	Project 2007-23 — Violation Severity Levels	No	Six sets of VSLs for various standards	Yes 2nd "Supp" (Thru 9/16/10)	Yes 6th (Thru 2/18/11)	Yes (Non-Binding Poll Thru 2/18/11)	NA - Non Binding Poll Only	Yes (3/10/11)	Yes (3/21/11)	Yes (5/19/11)		Completed
72	Project 2007-24 - Interpretation of TPL-002 and TPL-003	No	TPL-002-0a and TPL-003-0a	x	x	Yes 2nd (Thru 7/7/08)	Yes (7/7/08)	Yes (7/30/08)	Yes (10/24/08)	Yes (4/23/10)		Completed
73	Project 2007-27 — Interpretation of CIP-006 R1.1 by SCE&G	No	CIP-006, R1.1	x	x	Yes (Recirc Thru 12/4/07)	Yes (12/4/07)	Yes (2/12/08)	Yes (12/22/09)	Yes (5/19/11)		Completed
74	Project 2008-06 — Cyber Security — Order 706 (CIP-002-4)	High	CIP-002-4 thru CIP-009-4	x	Yes 1st (Thru 11/3/10)	Yes Recirc Thru 12/30/10) - passed	Yes (12/30/10)	Yes (1/24/11)	Yes (2/10/11)	Yes (4/19/12)		Completed
75	Project 2008-06 — Cyber Security — Order 706 (VRFs and VSLs)	No	CIP VRFs and VSLs	x	Yes 1st (Thru 4/20/09)	Yes (Recirc Thru 11/12/09)	Yes (11/12/09)	Yes (12/16/09)	Yes (12/18/09)	Yes (1/20/11)		Completed
76	Project 2008-07 — Interpretation of EOP-002-2 R6.3 and R7.1 by Brookfield Power	No	EOP-002-2, R6.3 and R7.1	x	x	Yes (Recirc Thru 8/31/09)	Yes (8/31/09)	No (Remanded 2/16/10)	NA	NA	2/16/10 NERC BOT: (1) Remands the proposed interpretation of EOP-002-2, Requirements R6.3 and R7.1, to the Standards Committee because the proposed interpretation adds requirements not in the standard, thereby exceeding the permissible scope of an interpretation, and (2) Directs the Standards Committee to initiate action to revise EOP-002-2 as appropriate	NA
77	Project 2008-08 — EOP VSL Revisions	No	EOP family of standards	Yes 1st (Thru 5/19/08)	Yes 2nd (Thru 12/3/09)	Yes (Non-Binding Poll Thru 2/18/11)	NA - Non Binding Poll Only	Yes (3/10/11)	Yes (3/21/11)	Yes (5/19/11)		Completed
78	Project 2008-09 — Interpretation of EOP-001-0 R1 by Regional Entity Compliance Managers	No	EOP-001-0, R1	x	x	Yes 4th (Recirc Thru 10/14/10)	Yes (10/14/10)	Yes (11/4/10)	Yes (9/9/11)	Yes (12/15/11)	The standard will now be referred to as EOP-001-2b	Completed
79	Project 2008-11 — Interpretation of VAR-002a by ICF Consulting	No	VAR-002-1.1b	x	x	Yes (Recirc Thru 1/6/09)	Yes (1/6/09)	Yes (2/10/09)	Yes (3/5/09)	Yes (9/16/10)		Completed
80	Project 2008-15 — Interpretation of CIP-006-1a By US Army Corps of Engineers	No	CIP-006-1a, R4	x	x	Yes (Recirc Thru 2/16/09)	Yes (2/16/09)	Yes (8/5/09)	Yes (12/22/09)	Yes (5/19/11)		Completed

Line No.	Project No. / Title	High Priority?	Associated Standard	SAR Posted?	Posted for Comment?	Posted For Ballot?	Industry Approved?	NERC BOT Approved?	Petitioned for FERC Approval?	FERC Approved	Comments	Project Status
81	Project 2008-18 — Interpretation of TOP-005-1 and IRO-005-1 by Manitoba Hydro	No	TOP-005-1 , R3 and IRO-005-1, R12	x	x	Yes (Recirc Thru 4/27/09)	Yes (4/27/09)	Yes (11/5/09)	Yes (11/24/09)	Yes (4/21/11)	Posted in Federal Register on 4/26/11	Completed
82	Project 2009-06 — Facility Ratings	Normal	FAC-008-3 (was FAC-008-2)	Yes 2nd (Thru 9/9/09)	Yes 3rd (Formal Thru 5/2/11)	Yes 6th (Recirculation Thru 5/23/11)	Yes (5/23/11)	Yes (5/24/11)	Yes (6/15/11)	Yes (11/17/11)	FAC-008-3 is effective the first day of the first calendar quarter that is twelve months after issuance of the FERC Order. FAC-008-3 combines FAC-008-1 and FAC-009-1 into a single standard.	Completed
83	Project 2009-08 — Nuclear Plant Interface Coordination	No	NUC-001-2	Yes 1st (Thru 3/18/09)	Yes 1st (Thru 3/18/09)	Yes (Recirc Thru 7/20/09)	Yes (7/20/09)	Yes (8/5/09)	Date?	Yes (1/21/10)		Completed
84	Project 2009-09 — Interpretation of CIP-001-1 by Covanta	No	CIP-001-1a	x	x	Yes (Recirc Thru 10/9/09)	Yes (10/09/09)	Yes (2/16/10)	Yes (4/21/10)	Yes (2/2/11)	Approved by Letter Order	Completed
85	Project 2009-10 — Interpretation of PRC-005-1 R1 by Compliance Monitoring Processes Working Group (CMPWG)	No	PRC-005-1, R1	x	x	Yes (Recirc Thru 8/6/09)	Yes (8/6/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (2/3/12)	Posted in Federal Register 2/13/12 - Effective 3/14/12	Completed
86	Project 2009-11 — Interpretation of IRO-010-1 R1.2 and R3 by WECC Reliability Coordination Subcommittee	No	IRO-010-1 R1.2 and R3 --> IRO-010-1a	x	x	Yes (Recirc Thru 6/5/09)	Yes (6/5/09)	Yes (8/5/09)	Yes (12/31/09)	Yes (3/17/11)	NOPR issued 11/18/10, Comments were due 1/24/11	Completed
87	Project 2009-12 — Interpretation of CIP-005-1 by PacifiCorp	No	CIP-005-3a	x	x	Yes (Recirc Thru 10/26/09)	Yes (10/26/09)	Yes (2/16/10)	Yes (4/21/10)	Yes (2/2/11)	Approved by Letter Order	Completed
88	Project 2009-13 — Interpretation of CIP-006-1 by PacifiCorp	No	CIP-006-2c	x	x	Yes (Recirc Thru 12/23/09)	Yes (12/23/09)	Yes (2/16/10)	Yes (4/20/10)	Yes (7/15/10)		Completed
89	Project 2009-14 — Interpretation of TPL-002-0 R1.3.10 by PacifiCorp	No	TPL-002-0, R1.3.10	x	x	Yes (Recirc Thru 8/6/09)	Yes (8/6/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (9/15/11)	Posted in Federal Register on 9/22/11 - Effective Date: This rule will become effective October 24, 2011	Completed
90	Project 2009-15 — Interpretation of MOD-001-1 R2 and R8 and MOD-029-1 R5 and R6 by NYISO	No	MOD-001-1, R2 and R8 and MOD-029-1 R5 and R6	x	x	Yes (Recirc Thru 7/17/09)	Yes (7/17/09)	Yes (11/5/09)	Yes (12/2/09)	Yes (9/16/10)		Completed
91	Project 2009-16 — Interpretation – CIP-007-1, R2 — Systems Security Management	No	CIP-007-2a	x	x	Yes (Initial Thru 9/21/09)	Yes (9/21/09)	Yes (11/5/09)	Yes (11/17/09)	Yes (3/18/10)		Completed
92	Project 2009-17 — Interpretation of PRC-004-1 and PRC-005-1 R2 by Y-W Electric and Tri-State G & T	No	PRC-004-1 and PRC-005-1	x	x	Yes 3rd (Recirc Thru 12/3/10)	Yes (12/3/10)	Yes (2/17/11)	Yes (4/15/11)	Yes (9/26/11)		Completed
93	Project 2009-18 — Withdraw Three Midwest ISO Waivers	No	BAL-006-2 and INT-003-3	x	x	Yes (Initial Thru 9/8/09)	Yes (9/8/09)	Yes (11/5/09)	Yes (11/20/09)	Yes (1/6/11)		Completed
94	Project 2009-21 — Cyber Security Ninety-day Response — CIP Family of Standards	No	CIP-002 through CIP-009, V3	Yes 1st (Thru 11/12/09)	Yes 1st (Thru 11/12/09)	Yes (Recirc Thru 12/14/09)	Yes (12/14/09)	Yes	Yes (1/19/10)	Yes (3/18/10)		Completed
95	Project 2009-23 — Interpretation of CIP-004-2 R3 by Army Corps of Engineers	No	CIP-004-2	x	x	Yes 2nd (Initial Thru 4/8/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
96	Project 2009-25 — Interpretation of BAL-001-01 and BAL-002-0 by BPA	No	BAL-001-0.1a and BAL-002-0	x	x	Yes 1st (Initial Thru 1/15/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
97	Project 2009-27 — Interpretation of TOP-002-2a R10 by FMPP	No	TOP-002-2a, R10	x	x	Yes (Recirc Thru 10/16/10)	Yes (10/16/10)	Yes (11/4/10)	Yes (4/15/11)	Yes (10/20/11)		Completed
98	Project 2009-28 — Interpretation of EOP-001-1 and EOP-001-2 R2.2 by FMPP	No	EOP-001-1 and EOP-001-2	x	x	Yes (Recirc Thru 10/15/10)	Yes (10/15/10)	Yes (11/4/10)	Yes (9/9/11)	Yes (12/15/11)	The standard will now be referred to as EOP-001-2b	Completed
99	Project 2009-29 — Interpretation of TOP-002-2a R6 by FMPP	No	TOP-002-2a, R6	x	x	Yes 1st (Initial Thru 2/22/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
100	Project 2009-30 — Interpretation of PRC-001-1 R1 by WPSC	No	PRC-001-1	x	x	Yes 1st (Initial Thru 2/26/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
101	Project 2009-31 — Interpretation of TOP-001-1 R8 by FMPP	No	TOP-001-1, R8	x	x	Yes 1st (Initial Thru 3/16/10)	Yes (3/16/10)	Yes (5/12/10)	Yes (7/16/10)	Yes (9/15/11)	Posted in Federal Register on 9/20/11 - Effective Date: This rule will become effective November 21, 2011	Completed
102	Project 2009-32 — Interpretation of EOP-003-1 R3 and R5 by FMPP	No	EOP-003-1, R3 and R5	x	x	Yes 2nd (Re-ballot Thru 3/31/10)	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
103	Project 2010-10 — FAC Order 729	No	FAC-013-2	Yes 1st (Thru 4/29/10)	Yes 3rd (Thru 1/8/11)	Yes 3rd (Recirc Thru 1/23/11)	Yes (1/23/11)	Yes (1/24/11)	Yes (1/28/11)	Yes (11/17/11)	FAC-013-2 is effective the first day of the calendar quarter twelve months after Commission approval.	Completed
104	Project 2010-12 — Order 693 Directives	No	BAL-002-1, EOP-002-3, FAC-002-1, MOD-021-1, PRC-004-2 and VAR-001-2	Yes 1st (Thru 7/13/10)	Yes 1st (Thru 7/13/10)	Yes 2nd (Recirc Thru 7/31/10)	Yes (7/31/10)	Yes (8/5/10)	Yes (9/9/10)	Yes (1/10/11)		Completed
105	Project 2010-13 — Relay Loadability Order	Normal	PRC-023-2	Yes 1st (Thru 9/19/10)	Yes 3rd (Thru 12/16/10)	Yes 3rd (Recirculation Thru 3/6/11)	Yes (3/6/11)	Yes (3/10/11)	Yes (3/18/11)	Yes (3/15/12)	Posted in Federal Register 3/21/12 - Effective Date 5/7/12	Completed
106	Project 2010-15 — Urgent Action Revisions to CIP-005-3	Urgent	CIP-005-4	Yes 1st (Thru 9/27/10)	Yes 3rd (Thru 4/28/11)	Yes 3rd (Thru 4/28/11)	NA	NA	NA	NA	Absorbed into Project 2008-06; Project 2010-15 curtailed	Project Curtailed
107	Project 2010-INT-04 Interpretation of EOP-001-1 R2.4 for FMPP	No	EOP-001-1, R2.4	x	x	x	NA	NA	NA	NA		Standards Committee curtailed work 04/12/11
108	Standard Processes Manual Revisions to Implement SPIG Recommendations	No			Thru 12/20/12	Successive ballot thru 12/20/12	Yes (12/20/12)					
109	Urgent Action SAR for Revision	No	BAL-004-1	Yes 2nd (Thru 10/18/07)	Yes 2nd (Thru 10/18/07)	Yes 1st (Recirc Thru 12/4/07)	Yes (12/4/07)	Withdrawn 8/16/12 ~~Yes (3/26/08)~~	~~Yes (3/11/09)~~	NA	The Board of Trustees withdrew its approval of BAL-004-1: Time Error Correction on August 16, 2012. BAL-004-1 has been withdrawn and retired. BAL-004-0 will remain enforceable.	Withdrawn

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 Compliance Application Notice Executive Tracking Summary

Revised: 8/6/2012

Further details regarding the individual documents may be found at: <http://www.nerc.com/page.php?cid=3%7C22%7C354>

CAN#	Project No. / Title	Associated Standard or Issue	Requirement	Advance Notice?	Posted for Comment?	Comments Posted?	CAN Issued?	Comments
CAN-0001	~~INT-004-2 R1: Compliance Application Notice~~	~~INT-004-2~~	~~1~~	~~*~~	~~*~~	~~*~~	~~Yes (5/5/10)~~	~~Retired August 31, 2011~~
CAN-0002	~~TOP-003-0 R1.3: Compliance Application Notice~~	~~TOP-003-0~~	~~1-3~~	~~*~~	~~*~~	~~*~~	~~Yes (5/5/10)~~	~~Retired August 31, 2011~~
CAN-0003	~~IRO-006-4.1 R2: Compliance Application Notice~~	~~IRO-006-4.1~~	~~2~~	~~*~~	~~*~~	~~*~~	~~Yes (5/5/10)~~	~~Retired August 31, 2011~~
CAN-0004	~~IRO-004-1 R3: Compliance Application Notice~~	~~IRO-004-1~~	~~3~~	~~*~~	~~*~~	~~*~~	~~Yes (5/5/10)~~	~~Retired August 31, 2011~~
CAN-0005	CIP-002-3 R3: Compliance Application Notice (Revised)	CIP-002-3	3	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0006	EOP-005 R7: Verification of Restoration Procedure (Revised)	EOP-005-1	7	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (11/11/11)	Yes (11/11/11)	Revised CAN posted 11/11/11
CAN-0007	CIP-004-2 R4.2 and CIP-004-3 R4.2: Compliance Application Notice	CIP-004-2, CIP-004-3	4.2, 4.2	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0008	PRC-005 R2: Basis for First Maintenance and Testing Date (Revised)	PRC-005-1	R2 Pre-June 18 evidence	x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (11/16/11)	Yes (4/10/12 - Revised)	Revised CAN posted 4/10/12
CAN-0009	FAC-008 and FAC-009: Facility Ratings and Design Specifications (Revised)	FAC-008 & FAC-009	R1, R1, R2	x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (11/11/11)	Revised CAN issued 11/11/11
CAN-0010	Implementation of Annual in Reliability Standards Requirements (Revised)	Definition of "Annual"		x	x	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0011	PRC-005 R2: Interval Start Date for New Equipment (Revised)	PRC-005-1	R2 - new equipment	x	x	Yes (11/16/11)	Yes (6/15/12 - Revised)	Revised CAN posted 6/15/12
CAN-0012	Completion of Periodic Activity Requirements During Implementation Plan (Revised)			x	Yes 1/21/11 (Thru 2/4/11)	Yes (11/16/11)	Yes (6/15/12 - Revised)	Revised CAN posted 6/15/12
CAN-0013	PRC-023 R1 and R2: Effective Dates for Switch-On-To-Fault Schemes (Revised)	PRC-023		x	Yes 1/21/11 (Thru 2/4/11)	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0015	Unavailability of NERC Software Tools			x	Yes 2/4/11 (Thru 2/18/11)	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0016	~~CIP-001 R1: Sabotage Reporting Procedure (Revised)~~	~~CIP-001~~		~~*~~	~~Revision~~	~~Yes (10/14/11)~~	~~Yes (10/14/11)~~	~~REMANDED 2/8/12 and then WITHDRAWN 2/16/12~~
CAN-0017	CIP-007 R5: Technical and Procedural System Access and Password Controls	CIP-007	R5	x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (11/11/11)	Revised CAN posted 11/11/11
CAN-0018	FAC-008 R1.2.1: Terminal Equipment (Revised)	FAC-008		x	Yes 8/31/11 (Thru 9/21/11) - Revision	Yes (11/11/11)	Yes (11/11/11)	Revised CAN posted 11/11/11
CAN-0019	CIP-007 R3.2 Implementation of Software Security Patches or Upgrades	CIP-007	R3.2	x	Yes 4/10/12 (Thru 6/4/12)	Yes (4/26/12)		
CAN-0020	Draft CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002	TPL-002, TPL-003, TPL-004		x	Yes 10/19/11 (Thru 11/9/11)	Yes (12/15/11)	Yes (12/15/11)	
CAN-0021	Draft CAN-0021 COM-002 Definition of Directive and Use of Three-Part Communications	COM-002		Yes (5/9/11)				
CAN-0022	CAN-0022 VAR-002-1.1b R1 and R3	VAR-002		x	Yes 4/19/11 (Thru 5/11/11)	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0023	CIP-005 R3, CIP-006 R6 Logging System Failures	CIP-005	R3	x	Yes 4/10/12 (Thru 6/4/12)	Yes (4/26/12)		
CAN-0024	Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CIP-002 through CIP-009		x	Yes 5/20/11 (Thru 6/10/11)	Yes (11/30/11)	Yes (12/15/11)	
CAN-0026	CAN-0026 TOP-006-X R3 Protection Relays	TOP-006		x	Yes 4/19/11 (Thru 5/11/11)	Yes (12/9/11)	Yes (12/9/11 - Revised)	Revised CAN posted 12/9/11
CAN-0027	Draft CAN-0027 TOP-003 R1.1 and R2 Generator	TOP-003		x	Yes (Thru 12/14/11)	Yes (12/21/11)	Yes (12/21/11)	
CAN-0028	TOP-006 R1.2: Reporting Responsibilities (Revised)	TOP-006		x	Yes 4/19/11 (Thru 5/11/11)	Yes (11/16/11)	Yes (11/16/11)	Revised CAN posted 11/16/11
CAN-0029	Protection System Misoperations, PRC-004-1 R1, R2, R3	PRC-004	R1, R2, R3	x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (12/9/11)	
CAN-0030	Draft CAN-0030 Attestations	Attestations		x	Yes 10/19/11 (Thru 11/9/11)	Yes (11/22/11)	Yes (12/9/11)	
CAN-0031	Acceptable Opening Dimensions, CIP-005 and CIP-006	CIP-005 and CIP-006		x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/16/11)	Yes (12/9/11)	
CAN-0033	PRC-023-1 Transmission Relay Loadability Criteria Selection	PRC-023		x	Yes 6/8/12 (thru 7/27/12)			
CAN-0034	EOP-002 R1, IRO-001 R2 and TOP-001 R1 Use of Authority Letters	EOP-002 IRO-001 TOP-001	R1 R2 R1	x	Yes 4/10/12 (Thru 5/7/12)	Yes (5/8/12)		
CAN-0038	PER-002 R4 Training Hours	PER-002	R4	x	Yes 4/10/12 (Thru 5/7/12)	Yes (5/8/12)		
CAN-0039	Filing DOE Form OE-417 Event Reports, EOP-004-1	EOP-004		x	Yes 9/23/11 (Thru 10/14/11)	Yes (11/11/11)	Yes (12/9/11)	
CAN-0040	BAL- 003 Frequency Response Calculation	BAL-003		x	Yes 11/2/11 (Thru 11/23/11)	Yes (12/9/11)	Yes (12/30/11)	
CAN-0043	PRC-005 Protection System Maintenance and Testing Evidence	PRC-005		x	Yes 11/2/11 (Thru 11/23/11)	Yes (12/9/11)	Yes (2/16/12 - Revised)	Revised CAN posted 2/16/12

Revised: 8/6/2012

NERC Compliance Application Notice Executive Tracking Summary

Further details regarding the individual documents may be found at: <http://www.nerc.com/page.php?cid=3%7C22%7C354>

CAN#	Project No. / Title	Associated Standard or Issue	Requirement	Advance Notice?	Posted for Comment?	Comments Posted?	CAN Issued?	Comments
CAN-0044	TOP-001 R1, R2 and R5 Operating Emergencies and Emergency Conditions	TOP-001	R1, R2, R5	x	Yes 6/8/12 (thru 7/27/12			

Acronyms:

CAN - Compliance Application Notice

NERC Reliability Standard Audit Worksheet (RSAW) Executive Tracking Summary

Revised: **12/28/2012**

Further details regarding the individual documents may be found at: <http://www.nerc.com/page.php?cid=31404>

RSAW#	Title	Posted for Comment?	Comments Posted?	RSAW Issued?	Comments
CIP-001-2a	Sabotage Reporting	x	x	10/13/2012	
CIP-006-5	Physical Security of BES Cyber System	x	x		
COM-002-2a	Communication and Coordination	x	x	11/14/2012	
COM-003-1	Operating Personnel Communications Protocols	x			
EOP-001-2b	Emergency Operations Planning	x	x	10/13/2012	
EOP-003-2	Load Shedding Plans	x	x	10/13/2012	
EOP-005-2	System Restoration from Blackstart Resources	x	x	10/13/2012	
EOP-006-2	System Restoration Coordination	x	x	10/13/2012	
EOP-008-1	Loss of Control Center Functionality	x	x	10/13/2012	
FAC-008-3	Facility Ratings	x	x	10/13/2012	
FAC-013-2	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon	x	x	10/13/2012	
IRO-014-1	Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	x	x	10/13/2012	
PER-005-1	System Personnel Training	Yes (Thru 4/30/12)	Yes (4/27/12)	Yes (8/10/12)	
PRC-023-2	Transmission Relay Loadability	x	x	11/15/2012	

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-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)		On 12/11/12 NERC submitted reply comments to the FERC 11/26/12 NOPR.	Pending FERC Approval
4	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
5	PRC-012-NPCC-01	Special Protection Systems	Yes (thru 8/18/08)									On Hold

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: 7/16/2012

Further details regarding the individual documents may be found at: <http://www.npcc.org/reqStandards/opOther.aspx>

Line No.	Type	Document	Description	Effective Date	Comments	Status
1	Criteria	A-01	Criteria for Review and Approval of Documents			
2	Criteria	A-10	Classification of BPS Elements			
3	Criteria	A-15	Disturbance Monitoring Equipment Criteria			
4	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System			Open Process - comment period through 8/27/12
5	Guideline	B-12	Guidelines for On-Line Computer System Performance During Disturbances			
6	Guideline	B-25	Guide to Time Suynchronization			
7	Guideline	B-26	Guide for Application of Disturbance Recording Equipement			
8	Guideline	B-27	Regional Critical Asset Identification Methodology			
9	Guideline	B-28	Guide for Generator Sequence of Events Monitoring			
10	Procedure	C-00	Listing of NPCC Documents by Type			
11	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures			
12	Procedure	C-05	Monitoring Procedures for Emergency Operation Criteria			
13	Procedure	C-07	Monitoring Procedures for the Guide for Rating Generating Capability			
14	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems			
15	Procedure	C-17	Procedures for Monitoring and Reporting Critical Operating Tool Failures			Open Process - Comment period ended 5/7/12
16	Procedure	C-21	Monitoring Procedures for Conformance with Normal and Emergency Transfer Limits			
17	Procedure	C-25	Procedure to Collect Power System Event Data			
18	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings			
19	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations			
20	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems			Open Process - comment period ended 3/27/11
21	Procedure	C-36	Procedures for Communications During Emergencies			
22	Procedure	C-39	Procedure to Collect Major Disturbance Event Data			
23	Procedure	C-42	Procedure for Reporting and Reviewing System Disturbances			
24	Procedure	C-43	NPCC Operational Review for the Integration of New facilities			
25	Procedure	C-44	NPCC Regional Methodology and Procedures for Forecasting TTC and ATC			
26	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	5/25/2011	[C-45 was previously reserved for CO-12 Seasonal Assessment Methodology (previously proposed but not issued - information included in the CO-12 Working Group scope instead)]	
27	Criteria	A-03 (retired)	Emergency Operation Criteria		A3 retired	Directory #2 established
28	Criteria	A-05 (retired)	Bulk Power System Protection Criteria		A5 retired	Directory #4 established
29	Criteria	A-07 (retired)	Revise Critical Component Definition (Glossary of Terms)		To be retired - pending approval of Glossary	Retired 10/26/11 (correction)
30	Criteria	A-08 (retired)	NPCC Reliability Compliance and Enforcement Program		A-08 retired	CCEP-1 established
31	Guideline	B-21 (retired)	NPCC Guide for Analysis and Reporting of Protection System Misoperations		Superseded by C-45	Replaced by Procedure C-45
32	Guideline	B-22 (retired)	Guidelines for Implementation of the NPCC Compliance Program		B-22 retired	CCEP-1 established
33	Procedure	C-32 (retired)	Review Process for NPCC Reliability Compliance Enforcement Program		C-32 retired	CCEP-1 established
34	Criteria	A-02 (retired)	Basic Criteria for Design and Operation Of Interconnected Power Systems		A2 retired	Directory #1 established
35	Criteria	A-04 (retired)	Maintenance Criteria for Bulk Power System Protection		A4 retired 7/11/2008	Directory #3 established
36	Criteria	A-06 (retired)	Operating Reserve Criteria		A6 retired 12/2/2010	Directory #5 established
37	Criteria	A-11 (retired)	Special Protection System Criteria			Directory #7 established
38	Criteria	A-12 (retired)	System Restoration Criteria		A12 draft replaced by Directory #8 10/21/08	Directory #8 established
39	Criteria	A-13 (retired)	NPCC Inc. Verification of Generator Gross and Net Real Power Capability		A13 retired 12/22/2008	
40	Criteria	A-14 (retired)	Verification of Generator Gross and Net Reactive Power Capability		A14 retired 12/22/2008	
41	Guideline	B-02 (retired)	Control Performance Guide		B2 retired	Content transferred to Directory #5 App. 5
42	Guideline	B-03 (retired)	Guidelines for Inter-AREA Voltage Control		B3 retired	Replaced by Procedure C-40
43	Guideline	B-04 (retired)	Guidelines for NPCC Area Transmission Reviews		B4 retired	Content transferred to Directory #1 App.B

NPCC Document Open Process Executive Tracking Summary

Revised: 7/16/2012

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

Line No.	Type	Document	Description	Effective Date	Comments	Status
44	Guideline	B-05 (retired)	Bulk Power System Protection Guide		B5 retired	Content transferred to Directory #4 App. A
45	Guideline	B-06 (retired)	Automatic Load Shedding Employing Underfrequency Threshold Relays		B6 retired	Replaced by Guideline B-07
46	Guideline	B-07 (retired)	Automatic Underfrequency Load Shedding Program		B7 retired	Content transferred to Directory #4 App. A
47	Guideline	B-08 (retired)	Guidelines for Area Review of Resource Adequacy		B8 retired	Content transferred to Directory #1 App.D
48	Guideline	B-09 (retired)	Guide for Rating Generating Capability		B9 retired	Replaced by Criteria A-13 Document on July 18, 2007
49	Guideline	B-10 (retired)	Guidelines for Requesting Exclusions		B10 retired	Content transferred to Directory #1 App. E
50	Guideline	B-11 (retired)	Special Protection System Guideline		B11 retired	Replaced by Criteria A-11
51	Guideline	B-13 (retired)	Guide for Reporting System Disturbances		B13 retired	Replaced by Procedure C-42
52	Guideline	B-24 (retired)	Security Guidelines for Protection System IEDS		B24 retired	Content transferred to Directory #4 App. A
53	Procedure	C-03 (retired)			C3 retired	Replaced by Procedure C-36
54	Procedure	C-04 (retired)	Monitoring Procedure for Guides Inter-AREA Volt Control		C4 retired	Content transferred to Directory #1 App. G
55	Procedure	C-08 (retired)	Monitoring Procedures for Control Performance Guide		C8 retired	Content transferred to Directory #5 App. #5
56	Procedure	C-09 (retired)	Monitoring Procedures for Operating Reserve Criteria		C9 retired	Content transferred to Directory #5 App. #2
57	Procedure	C-10 (discontinued)			C10 discontinued	
58	Procedure	C-11 (retired)	Monitoring Procedures for Interconnected System Freq Response		C11 retired	Content transferred to Directory #5 App. #1
59	Procedure	C-12 (retired)	Procedure Shared Activation Ten Minute Reserve		C12 retired	Content transferred to Directory #5 Sect 5.8 & App. #4
60	Procedure	C-13 (retired)	Operational Planning Coordination		C13 retired	Content transferred to Directory #1 App. F
61	Procedure	C-14 (retired)			C14 retired	Procedure C-14 was incorporated in Procedure C-13
62	Procedure	C-16 (retired)	Procedure for Review of New or Modified BPS SPS		C16 retired	Content transferred to Directory #7 App.B
63	Procedure	C-18 (retired)	Procedure for Test & Analysis Extreme Contingencies		C18 retired	Content transferred to Directory #1 App.C
64	Procedure	C-20 (retired)	Procedures During Abnormal Operating Conditions		C20 retired	Content transferred to Directory #5 App. #3
65	Procedure	C-22 (retired)	Procedure for Reporting & Review Proposed BPS Protection Systems		C22 retired	Content transferred to Directory #4 App. A
66	Procedure	C-35 (retired)	NPCC Inter-Area Power System Restoration Procedure		C35 retired	Incorporated within Directory #8 System Restoration
67	Procedure	C-37 (retired)	Operating Procedures for ACE Diversity Interchange		C37 retired	Content transferred to Directory #5 Sect.5.11
68	Procedure	C-38 (retired)	Procedure for Operating Reserve Assistance			Content will be transferred to new Directory #5 Reserve
69	Procedure	C-40 (retired)	Procedures for Inter-AREA Voltage Control		C40 retired	Content transferred to Directory #1 App. G & Directory #2 App. B
70	Procedure	Cost Effectiveness Analysis Procedure - CEAP				Open Process - Comment period through 9/19/11
71	Glossary	NPCC Glossary of Terms				Open Process - Comment period through 9/12/11

Acronyms:

Line No.	Document	Developed From	Title of Directory	Version Date	Phase	Task Force Review	Posted Open Process?	RCC Approval?	Full Membership Ballot?	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	12/1/09 (V0)		TFCP(CP11) and TFCO (CO7)	Initial Open Process pending resolution of TFCO criteria interpretation.				TFCP coordinating the overall Phase 2 reformatting of Directory #1. TFCO and TFSS requested by TFCP to review portions of the reformatted draft prior to the initial Open Process posting. TFCO continues to review the Operating Criteria portion of Directory#1 in order to resolve differences within TFCO regarding the interpretation of certain aspects of the Operating Criteria. TFCO Working Group C07 has been assigned to achieve consensus surrounding this issue. TFCP posting pending resolution of the TFCO issues.
2	Directory #2	Criteria A-3	Emergency Operations	1/6/11 (V3)		TFCO					Phase 2 reformatting pending TFCO resources.
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	6/3/09 (V1)		TFSP					Clarification of the criteria surrounding Section 5.6.2 of Directory#3 Maintenance Criteria for Bulk Power System Protection (completed Dec. 20, 2012). Clarification of the criteria surrounding Section 5.7.1 of Directory#3 Maintenance Criteria for Bulk Power System Protection (completed Dec. 20, 2012).
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	12/1/09 (V0)		TFSP				Open Process posting expected in 2013.	TFSP coordinating the Phase 2 reformatting of Directory #4 including a review of the criteria against the recently approved PRC -005. RSC and CC also approved compliance requirements in the Phase 2 draft of D#4 in lieu of the standard Phase 2 format.
5	Directory #5	Criteria A-6	Reserve	12/19/2012 (V1)		TFCO				Revisions to Version 0 of Directory #5 approved by the NPCC Full Members in October 2012.	
6	Directory #6		Regional Reserve Sharing		2				Passed 04/09/2012	Directory #6 approved by the NPCC Full Members in Phase 2 format in April 2012.	
7	Directory #7	Criteria A-11	Special Protection Systems	12/27/07 (V0)	2	TFSP	Yes (Comment Thru 11/12/12)				TFSP coordinating the Phase 2 reformatting of Directory #7. TFSP reviewing comments received from the Open Process Posting that concluded in October 2012. RSC and CC also approved compliance requirements in the Phase 2 draft of D#7 in lieu of the standard Phase 2 format.
8	Directory #8	Criteria A-12	System Restoration	10/22/10 (V1)		TFCO					TFCO working group CO11 reviewing initial Phase 2 draft of Directory #8.
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	7/7/09 (V1)	2				Passed 12/28/11	Directory#9 Phase 2 reformatting complete December 2011.	
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	7/7/09 (V1)	2				Passed 12/28/11	Directory#10 Phase 2 reformatting complete December 2011.	
11	Directory #11										
12	Directory #12		Under frequency Load Shedding Program Requirements	1/6/11 (V2)			Yes (Thru 10/26/12)			NPCC will retire Directory#12 upon Regional Standard PRC-006-NPCC-1 Automatic UFLS receiving approvals in all regional jurisdictions.	Directory#12--Automatic UFLS Program Requirements posted for comment in the NPCC Open Process through March 14, 2013.

Acronyms:
MC - Members Committee
RCC - Reliability Coordinating Committee

NPCC Directory Interpretation Executive Tracking Summary

Further details regarding the individual documents may be found at:

Line	Document	Title of Directory	Task Force Responsible for Review
1	Directory#8	System Restoration	TFC0
2	Directory#3	Maintenance Criteria for Bulk Power System Protection	TFSP
3	Directory#3	Maintenance Criteria for Bulk Power System Protection	TFSP
4	Directory#3	Maintenance Criteria for Bulk Power System Protection	TFSP

<https://www.npcc.org/Standards/Directory%20Interpretations/Forms/Public%20List.aspx>

Interpretation Rendered on Behalf Of

Date Interpretation Issued

NYSPSC

6/18/2012

Bangor Hydro

8/28/2012

Acumen Engineered Solutions

12/14/2012

Con Ed

12/14/2012

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Regional Reliability Standard PRC-006-NPCC-1) **Docket No. RM12-12-000**
Automatic Underfrequency Load Shedding)

**REPLY 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 reply comments in response to the comments submitted on November 26, 2012, on the Federal Energy Regulatory Commission’s (“FERC” or the “Commission”) September 20, 2012, Notice of Proposed Rulemaking (“NOPR”)² regarding the proposed regional Reliability Standard PRC-006-NPCC-1 (Automatic Underfrequency Load Shedding).

I. BACKGROUND

The proposed regional Reliability Standard applies to generator owners, planning coordinators, distribution providers, and transmission owners in the Northeast Power Coordinating Council Region and is designed to ensure the development of an effective automatic underfrequency load shedding (“UFLS”) program to preserve the security and integrity of the Bulk-Power System during declining system frequency events, in coordination with the NERC continent-wide UFLS Reliability Standard PRC-006-1. Comments on the NOPR were due on November 26, 2012. Pursuant to Rule 212, NERC respectfully offers these limited reply comments for purposes of clarification.

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. *North American Electric Reliability Corporation*, 116 FERC ¶ 61,062 (2006).

² *Regional Reliability Standard PRC-006-NPCC-1—Automatic Underfrequency Load Shedding*, 140 FERC ¶ 61,203 (September 20, 2012) (“NOPR”).

II. COMMENTS

A. NERC Reliability Standard PRC-006-1, Automatic Underfrequency Load Shedding and Load Shedding Plans

Dominion Resources Services, Inc. (“Dominion”) states in its comments that in the final rule approving the continent-wide NERC Reliability Standard, PRC-006-1, the “Commission agreed with NERC’s comments that it is appropriate for planning coordinators to consider generators that trip outside the UFLS set points when designating UFLS programs, but it is inappropriate for planning coordinators to determine whether mitigation is necessary and who will be responsible for providing mitigation.”³ As NERC noted in its June 6, 2012, Motion to Correct the Record, the Commission’s characterization of NERC’s comments in Order No. 763 is incorrect.⁴

As NERC stated:

NERC believes Order No. 763 takes certain statements made by NERC out of context, which could potentially affect the Commission’s assessment of pending and future regional standards addressing underfrequency load shedding or future versions of the continent-wide standard. NERC said in its NOPR comments that it is not appropriate for a Reliability Standard to prescribe *how* the Planning Coordinator will determine whether mitigation is necessary or who would be responsible for providing the mitigation, not *if* the mitigation is necessary. These are two completely different issues.⁵

Additionally, NERC clarified that it did not intend to say that it is inappropriate for Planning Coordinators to determine whether mitigation is necessary and who will be providing mitigation. On the contrary, the Planning Coordinator is one of the functional entities with responsibility for maintaining the reliability of the Bulk-Power System. One of the Planning Coordinator’s

³ Comments of Dominion Resources Services, Inc., Regional Reliability Standard PRC-006-NPCC-1-Automatic Underfrequency Load Shedding, Docket No. RM12-12-000 at 8 (November 26, 2012).

⁴ Motion of the North American Electric Reliability Corp. to Correct the Record, Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards, Docket No. RM11-20-000 at 2 (June 6, 2012).

⁵ *Id.*

responsibilities is to ensure that UFLS programs meet the performance characteristics defined in PRC-006-1. For these reasons, Dominion’s characterization of NERC’s comments is incorrect.⁶

NERC did state in its comments on the continent-wide Reliability Standard PRC-006-1, that the approach in the standard “provides Planning Coordinators with needed flexibility in developing UFLS programs based on the conditions and circumstances within their Planning Coordinator areas” and the various islands that are studied.⁷ While NERC notes that it is inappropriate for a Reliability Standard to supplant the Planning Coordinator’s role in establishing UFLS program requirements, the proposed regional Reliability Standard reflects the NPCC Planning Coordinators’ collective assessment of how to address this concern. The proposed regional Reliability Standard similarly establishes requirements for frequency setpoints, time delays, and amounts of load to shed based on the Planning Coordinators’ collective assessments, even though it would not be appropriate to prescribe these parameters in a continent-wide standard.

NERC respectfully submits that PRC-006-NPCC-1 is just, reasonable, not unduly discriminatory or preferential, and in the public interest and should be approved by the Commission.

B. Compensatory Load Shedding, As Provided for in PRC-006-NPCC-1, Does Not Jeopardize the Reliability of the Bulk-Power System

Commenters have expressed technical concerns regarding the implementation of PRC-006-NPCC-1 and potential overfrequency excursions; however, these concerns are overstated.⁸

⁶ See also, *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order Granting Clarification, 140 FERC ¶ 61,164 at P 12 (2012) (“With regard to NERC’s request, we grant the motion and clarify that NERC stated in its NOPR comments that it is not appropriate for the Reliability Standards to prescribe *how* a planning coordinator determines whether mitigation is necessary or who is responsible for providing mitigation.”) (emphasis in original).

⁷ Motion of the North American Electric Reliability Corp. to Correct the Record, *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Docket No. RM11-20-000 at 3 (June 6, 2012).

⁸ Comments of Dominion Resources Services, Inc., *Regional Reliability Standard PRC-006-NPCC-1-Automatic Underfrequency Load Shedding*, Docket No. RM12-12-000 at 3 (November 26, 2012) (“there are

Compensatory load shedding can be an effective tool for counteracting the effect of generator tripping that is not coordinated with UFLS program operation provided the amount of compensatory loadshedding is limited in magnitude and included in Planning Coordinator assessments. The concerns noted by commenters regarding potential overfrequency excursions due to overcompensating when a generating unit with non-conforming trip settings is off-line⁹ would be appropriate if compensatory loadshedding was applied to large generating units or if the provision was open-ended with applicability to future generating units not studied by the Planning Coordinator. NERC notes that compensatory load shedding as defined in the proposed Regional Standard, with applicability limited to a defined amount of generating capacity that is included in Planning Coordinator assessments, does not jeopardize reliability of the Bulk-Power System.

technical difficulties associated with Requirements R16.3 and R18 which would likely have an adverse impact on reliability.”).

⁹ *Id.* (“For example, consider a load shed program that is designed assuming the need to shed load equivalent to rated capacity for a non-conforming generator and a frequency event occurs when this generator is off-line. The program sees the frequency at the trigger level and sheds the load equivalent to the non-conforming generator. However, since that generator was not actually on-line, there is no additional loss of generation, but the megawatt load equivalent of the generator (that is not designed into the UFLS scheme) is lost anyway. If the UFLS program then implements the next level of designed reduction of load, this may result in a subsequent rebound in frequency. This may very well result in overshoot that is more than designed for, resulting in a generator trip from over-frequency.”).

III. CONCLUSION

For the reasons stated above, NERC respectfully requests that the Commission accept these comments for consideration.

Respectfully submitted,

/s/ Stacey Tyrewala

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President, General Counsel and
Corporate Secretary
Holly A. Hawkins
Assistant General Counsel
Stacey Tyrewala
Attorney
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

December 11, 2012

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD12-6-000

December 12, 2012

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Willie L. Phillips
Attorney for North American Electric Reliability Corporation

Reference: Approval of Interpretation to Reliability Standard CIP-004

Dear Mr. Phillips:

On August 1, 2012, the North American Electric Reliability Corporation (NERC) submitted a petition proposing to approve an Interpretation of Requirements R2, R3, and R4 to Reliability Standard CIP-004-4.

The proposed interpretation clarifies that all cyber access must be authorized, and all authorized cyber access requires compliance with Requirements R2, R3, and R4 of CIP-004-4.

Notice of this filing was issued on August 2, 2012, with protests and interventions due on or before August 22, 2012.

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 protests were filed.

NERC's uncontested filing is 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.

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.

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

141 FERC ¶ 61,243
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM12-9-000; Order No. 772]

Regional Reliability Standard PRC-006-SERC-01 —Automatic
Underfrequency Load Shedding Requirements

(Issued December 20, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) approves regional Reliability Standard PRC-006-SERC-01 (Automatic Underfrequency Load Shedding Requirements), submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC). Regional Reliability Standard PRC-006-SERC-01 is designed to ensure that automatic underfrequency load shedding protection schemes, designed by planning coordinators and implemented by applicable distribution providers and transmission owners in the SERC Reliability Corporation Region, are coordinated to mitigate the consequences of an underfrequency event effectively. The Commission approves the related violation risk factors, with one modification, violation severity levels, implementation plan, and effective date proposed by NERC.

EFFECTIVE DATE: This rule will become effective **[Insert date 60 days after publication in the FEDERAL REGISTER]**.

FOR FURTHER INFORMATION CONTACT:

Susan Morris (Technical Information)
Office of Electric Reliability, Division of Reliability Standards
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-6803
Susan.Morris@ferc.gov

Matthew Vlissides (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-8408
Matthew.Vlissides@ferc.gov

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony T. Clark.

Regional Reliability Standard PRC-006-SERC-01 — Docket No. RM12-9-000
Automatic Underfrequency Load Shedding
Requirements

FINAL RULE

Order No. 772

(Issued December 20, 2012)

1. Under section 215 of the Federal Power Act (FPA), the Commission approves regional Reliability Standard PRC-006-SERC-01 (Automatic Underfrequency Load Shedding Requirements) in the SERC Reliability Corporation (SERC) Region. The Commission also approves the related violation risk factors (VRF), with one modification, violation severity levels (VSL), implementation plan, and effective date proposed by the North American Electric Reliability Corporation (NERC). NERC submitted regional Reliability Standard PRC-006-SERC-01 to the Commission for approval and the new standard is designed to ensure that automatic underfrequency load shedding (UFLS) protection schemes, designed by planning coordinators and implemented by applicable distribution providers and transmission owners in the SERC Region, are coordinated to mitigate the consequences of an underfrequency event effectively.

I. Background

A. Mandatory Reliability Standards

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by NERC, subject to Commission oversight, or by the Commission independently.¹

3. Reliability Standards that NERC proposes to the Commission may include Reliability Standards that are proposed by a Regional Entity to be effective in that region.² In Order No. 672, the Commission noted that:

As a general matter, we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.³

¹ See 16 U.S.C. § 824o(e) (2006).

² 16 U.S.C. § 824o(e)(4). A Regional Entity is an entity that has been approved by the Commission to enforce Reliability Standards under delegated authority from the ERO. See 16 U.S.C. § 824o(a)(7) and (e)(4).

³ *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 291, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

When NERC reviews a regional Reliability Standard that would be applicable on an interconnection-wide basis and that has been proposed by a Regional Entity organized on an interconnection-wide basis, NERC must rebuttably presume that the regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.⁴ In turn, the Commission must give “due weight” to the technical expertise of NERC and of a Regional Entity organized on an interconnection-wide basis.⁵

4. On April 19, 2007, the Commission accepted delegation agreements between NERC and each of the eight Regional Entities.⁶ In the order, the Commission accepted SERC as a Regional Entity organized on less than an interconnection-wide basis. As a Regional Entity, SERC oversees Bulk-Power System reliability within the SERC Region, which covers a geographic area of approximately 560,000 square miles in a sixteen-state area in the southeastern and central United States (all of Missouri, Alabama, Tennessee, North Carolina, South Carolina, Georgia, Mississippi, and portions of Iowa, Illinois, Kentucky, Virginia, Oklahoma, Arkansas, Louisiana, Texas and Florida).

⁴ 16 U.S.C. § 824o(d)(3).

⁵ *Id.* § 824o(d)(2).

⁶ *North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh’g*, 120 FERC ¶ 61,260 (2007).

B. NERC Petition

5. On February 1, 2012, NERC submitted a petition to the Commission seeking approval of regional Reliability Standard PRC-006-SERC-01.⁷ NERC stated that regional Reliability Standard PRC-006-SERC-01 is designed to ensure that automatic UFLS protection schemes, designed by planning coordinators and implemented by applicable distribution providers and transmission owners in the SERC Region, are coordinated to mitigate the consequences of an underfrequency event effectively.⁸ According to NERC, regional Reliability Standard PRC-006-SERC-01 adds specificity for UFLS schemes in the SERC Region that are not present in the NERC UFLS Reliability Standard PRC-006-1.⁹ NERC explained that regional Reliability Standard PRC-006-SERC-01 effectively mitigates, in conjunction with Reliability Standard PRC-006-1, the consequences of an underfrequency event while accommodating differences in system transmission and distribution topology among SERC planning coordinators resulting from historical design criteria, makeup of load demands, and generation resources.¹⁰

⁷ North American Electric Reliability Corp., February 1, 2012 Petition for Approval of Regional Reliability Standard PRC-006-SERC-01 (NERC Petition). Regional Reliability Standard PRC-006-SERC-01 is not codified in the CFR. However, it is available on the Commission's eLibrary document retrieval system in Docket No. RM12-9-000 and is available on the NERC's website, www.nerc.com.

⁸ NERC Petition at 7.

⁹ *Id.* at 18.

¹⁰ *Id.* at 18-19.

6. In the petition, NERC also proposed violation risk factors and violation severity levels for each Requirement of the regional Reliability Standard, an implementation plan, and an effective date. NERC stated that these proposals were developed and reviewed for consistency with NERC and Commission guidelines. NERC proposed specific implementation plans for each Requirement in the regional Reliability Standard, with the regional Reliability Standard becoming fully effective thirty months after the first day of the first quarter following regulatory approval. NERC stated that the implementation plan is reasonable, as it balances the need for reliability with the practicability of implementation.

C. Notice of Proposed Rulemaking

7. On July 19, 2012, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve regional Reliability Standard PRC-006-SERC-01 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.¹¹ The Commission proposed to approve regional Reliability Standard PRC-006-SERC-01 because it is designed to work in conjunction with NERC Reliability Standard PRC-006-1 to mitigate the consequences of an underfrequency event effectively, while accommodating differences in system transmission and distribution topology among SERC planning coordinators due to historical design criteria, makeup of load demands,

¹¹ *Regional Reliability Standard PRC-006-SERC-01 —Automatic Underfrequency Load Shedding Requirements*, Notice of Proposed Rulemaking, 77 Fed. Reg. 43,190 (July 24, 2012), 140 FERC ¶ 61,056 (2012) (NOPR).

and generation resources. The NOPR determined that PRC-006-SERC-01 covers topics not covered by the corresponding NERC Reliability Standard PRC-006-1 because it adds specificity for UFLS schemes in the SERC Region.

8. While proposing to approve regional Reliability Standard PRC-006-SERC-01, the NOPR identified a possible inconsistency between, on the one hand, the separate rationale for Requirement R6 of the regional Reliability Standard and, on the other, Order No. 763, which approved NERC Reliability Standard PRC-006-1.¹²

9. Regional Reliability Standard PRC-006-SERC-01, Requirement R6 states:

R6. Each UFLS entity shall implement changes to the UFLS scheme which involve frequency settings, relay time delays, or changes to the percentage of load in the scheme within 18 months of notification by the Planning Coordinator.

[Violation Risk Factor: Medium][Time Horizon: Long-term Planning]

10. The rationale for Requirement R6 included in the NERC petition states:

Rationale for R6:

The SDT believes it is necessary to put a requirement on how quickly changes to the scheme should be made. This requirement specifies that changes must be made within 18 months of notification by the PC [planning coordinator]. The 18 month interval was chosen to give a reasonable amount of time for making changes in the field. All of the SERC region has existing UFLS schemes which, based on periodic simulations, have provided reliable protection for years. Events which result in islanding and an activation of the UFLS schemes are extremely rare. Therefore, the SDT does not believe that changes to an existing UFLS scheme will be

¹² *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order No. 763, 139 FERC ¶ 61,098 (2012).

*needed in less than 18 months. However, if a PC desires that changes to the UFLS scheme be made faster than that, then the PC may request the implementation to be done sooner than 18 months. The UFLS entity may oblige but will not be required to do so.*¹³

11. The NOPR stated that the rationale for Requirement R6 could result in Requirement R6 being read to allow applicable entities not to adopt a planning coordinator's schedule for implementing corrective actions to UFLS schemes if the schedule is less than 18 months. The NOPR stated that such an interpretation would be inconsistent with Order No. 763, which, in approving PRC-006-1, held that planning coordinators should be responsible for establishing schedules for the completion of corrective actions in response to UFLS events.¹⁴ The NOPR stated that the Commission interprets the language in Requirement R6, that UFLS entities must implement changes "within 18-months," as a "maximum" timeframe to comply with a planning coordinator's schedule to implement changes to UFLS schemes, but the interpretation further recognized that the planning coordinator could establish a schedule requiring the changes to be implemented in less time. The NOPR stated that the inclusion of a maximum timeframe is more stringent than Reliability Standard PRC-006-1, which does not contain a maximum timeframe to implement changes to a UFLS scheme.

¹³ NERC Petition, Exhibit A at 14 (emphasis added).

¹⁴ Order No. 763, 139 FERC ¶ 61,098 at P 48 (citing Reliability Standard PRC-006-1, Requirement R9, "Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets.").

12. The NOPR proposed to approve the related violation risk factors, with one modification, violation severity levels, implementation plan, and effective date proposed by NERC. The NOPR proposed to direct NERC to modify the violation risk factor assigned to Requirement R6 from “medium” to “high” to make it consistent with the Commission’s VRF guidelines and the violation risk factor for Requirement R9 of NERC Reliability Standard PRC-006-1, since both Requirements address a similar reliability goal.¹⁵

13. In response to the NOPR, comments were filed by NERC and three interested entities regarding the Commission’s interpretation of Requirement R6, aspects of Requirement R2 that were not addressed in the NOPR, and the proposed modification to the violation risk factor associated with Requirement R6.¹⁶

II. Discussion

14. Pursuant to FPA section 215(d)(2), we approve regional Reliability Standard PRC-006-SERC-01 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. PRC-006-SERC-01 is designed to work in conjunction with NERC

¹⁵ *North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, *order on reh’g*, 120 FERC ¶ 61,145 (2007).

¹⁶ Comments were received from Dominion Resources Services, Inc. (Dominion), on behalf of Virginia Electric and Power Company d/b/a Dominion Virginia Power, Dominion Energy Kewaunee, Inc., Dominion Nuclear Connecticut, Inc. Dominion Energy Brayton Point, LLC, Dominion Energy Manchester Street, Inc., Elwood Energy, LLC, Kincaid Generation, LLC and Fairless Energy, LLC; Midwest Independent Transmission System Operator, Inc. (MISO); and SERC. Dominion and SERC also filed reply comments.

Reliability Standard PRC-006-1 to mitigate the consequences of an underfrequency event effectively while accommodating differences in system transmission and distribution topology among SERC planning coordinators due to historical design criteria, makeup of load demands, and generation resources.¹⁷ As indicated above, PRC-006-SERC-01 addresses topics not covered by the corresponding NERC Reliability Standard PRC-006-1 because it adds specificity for UFLS schemes in the SERC Region. The Commission also approves the related violation risk factors, with one modification, violation severity levels, implementation plan, and effective date proposed by NERC.

15. We address below the three issues raised in the comments to the NOPR.

A. PRC-006-SERC-01, Requirement R6

16. In the NOPR, the Commission interpreted Requirement R6 as imposing an 18-month maximum schedule for implementing changes to UFLS schemes in the SERC Region but, consistent with NERC Reliability Standard PRC-006-1 and Order No. 763, as allowing planning coordinators to require applicable entities to implement changes in less time.¹⁸ The NOPR stated that the proposed rationale for Requirement R6 was potentially inconsistent with this interpretation and the treatment of NERC Reliability Standard PRC-006-1 in Order No. 763.

¹⁷ NERC Petition at 18.

¹⁸ NOPR, 140 FERC ¶ 61,056 at P 16.

Comments

17. In its initial comments, SERC points to NERC's compliance filing to Order No. 763, in which NERC states that PRC-006-SERC-01 does not replace PRC-006-1 for UFLS entities in the SERC Region and that such entities must comply with both standards. To explain the basis for the 18-month schedule in PRC-006-SERC-01, Requirement R6, SERC states that the drafting team was concerned that, in situations where a UFLS entity is not a planning coordinator, planning coordinators might impose unreasonable schedules on UFLS entities when major UFLS scheme changes are made, not as part of a corrective action plan (i.e., actions taken in response to event assessments made pursuant to PRC-006-1, Requirement R11), but for other reasons (e.g., "for consistency purposes, a change in UFLS scheme philosophy, or for other reasons").¹⁹ SERC states that planning coordinators are allowed to make such changes under PRC-006-1, but Requirement R3 of PRC-006-1 does not require planning coordinators to consider UFLS entity budgeting and procurement limitations when establishing implementation schedules.

18. SERC states that the drafting team felt it was important to provide a practical timeframe for UFLS entities that are not planning coordinators by establishing an upper bound on the timeframe for implementing major changes to an entity's UFLS scheme and

¹⁹ SERC Initial Comments at 4.

to ensure that the UFLS entities that are not planning coordinators have adequate time to budget, procure, and install the necessary equipment.²⁰

19. SERC states that it does not oppose the Commission's interpretation of Requirement R6 (i.e., that Requirement R6 does not provide a UFLS entity with the discretion not to follow the schedule set by the planning coordinator when the schedule is less than 18 months). SERC proposes to revise the rationale statement for Requirement R6 to make it consistent with the Commission's interpretation.²¹

20. NERC states that, in its compliance filing to Order No. 763, it explained that UFLS entities in the SERC Region must comply with PRC-006-1 and PRC-006-SERC-01 and that the latter does not replace the former. NERC stated in the compliance filing that "UFLS entities must meet the schedule set by the Planning Coordinator to comply with PRC-006-1, Requirement R9, but the timeframe must not exceed 18 months in the SERC Reliability Corporation Region to comply with PRC-SERC-006-1, Requirement R6."²² NERC states that SERC does not oppose NERC's clarification, above, and further

²⁰ SERC states that 26 of the 43 UFLS entities in the SERC Region do not serve as their own planning coordinators. SERC Initial Comments at 4.

²¹ SERC proposes to revise the rationale to include a statement that "[i]f a PC [planning coordinator] determines there is a need for changing the UFLS scheme faster than 18 months, then the PC may require the implementation to be done sooner as allowed by NERC Reliability Standard PRC-006-1." *Id.* at 6.

²² NERC, Compliance Filing, Docket No. RM11-20-002, at 6-7 (filed Aug. 9, 2012).

states that it supports SERC's proposed revision to the rationale statement for Requirement R6.

21. Dominion states in its initial comments that it supports PRC-006-SERC-01 as proposed but is concerned that it may conflict with Order No. 763. Dominion states that NERC's compliance filing to Order No. 763 adds "an unreasonable burden and complexity in the compliance efforts of affected registered entities."²³ Specifically, Dominion is concerned that compliance with PRC-006-1 and PRC-006-SERC-01 will create a "new, or at least unrealized, level of complexity imposed upon registered entities."²⁴ Dominion states that it "recommends that the Commission approve the SERC regional standard but remand Requirement R6 and direct it be modified to be consistent with the scheduling requirements of Order No. 763 ... to require each UFLS entity in the SERC region to implement changes to the UFLS scheme within the lesser of 18 months of notification by the planning coordinator, or the schedule established by the planning coordinator."²⁵

22. In responsive comments, SERC states that Dominion's concerns have been adequately addressed. SERC states that the Commission indicated in the NOPR that it will not read Requirement R6 as providing UFLS entities with the discretion not to

²³ Dominion Initial Comments at 3.

²⁴ *Id.* at 4.

²⁵ *Id.* at 4-5 (emphasis in original).

follow the schedule set by planning coordinators when the schedule is less than 18 months. SERC also states that it proposed, in its initial comments, to revise the rationale for Requirement R6 to make the rationale consistent with this interpretation.

23. In reply to SERC's responsive comments, Dominion disagrees that its concerns have been adequately addressed. Dominion states that "it is unjust to hold a registered entity responsible for compliance to any requirement within a reliability standard where such compliance is dependent upon that registered entity having also read, and taken into consideration, all statements issued by FERC, NERC and the Regional Entity in this docket."²⁶

Commission Determination

24. The Commission affirms the interpretation of Requirement R6 set forth in the NOPR and accepts NERC and SERC's proposal to revise the rationale statement for Requirement R6, as set forth in NERC and SERC's comments. NERC, SERC, and Dominion do not oppose the Commission's interpretation of Requirement R6.

25. The remaining dispute, therefore, centers on Dominion's request that Requirement R6 should be revised to eliminate any ambiguity, as opposed to relying on the Commission's interpretation of Requirement R6 and the proposed revision to the separate rationale for Requirement R6. We reject this request because, as we stated in the NOPR, the ambiguity regarding Requirement R6 was a result of the separate rationale statement

²⁶ Dominion Reply Comments at 2-3.

for Requirement R6.²⁷ Absent the problematic language in the rationale, there is no inconsistency created by the text of Requirement R6 itself. As NERC notes, UFLS entities must comply with both PRC-006-1 and PRC-006-SERC-01.²⁸ A plain reading of Requirement R6 (i.e., that UFLS entities shall implement changes within 18 months of notification by planning coordinators) in conjunction with a reading of PRC-006-1 (i.e., requiring UFLS entities to follow the schedules set by planning coordinators) indicates that, in the SERC Region, there will be an 18-month maximum period for implementing changes to UFLS schemes but planning coordinators may require UFLS entities to complete changes in less time consistent with PRC-006-1. Accordingly, we accept NERC and SERC's proposal to revise the rationale statement for Requirement R6, consistent with SERC's proposal, but we will not require the revision to Requirement R6 proposed by Dominion. We direct NERC and SERC to make an informational filing within 30 days of the effective date of this final rule that provides a schedule for implementing the revision.

B. PRC-006-SERC-01, Requirements R2.3, R2.4, R2.5, and R2.6

26. In the NOPR, the Commission noted that Requirement R2 requires each planning coordinator to select or develop an automatic UFLS scheme (percent of load to be shed,

²⁷ NOPR, 140 FERC ¶ 61,056 at P 16 (“[w]e are concerned, however, that the italicized language in the rationale NERC provides for Requirement R6 may be incompatible with Order No. 763”).

²⁸ See Order No. 672 at P 294 (“A user, owner or operator must follow the Reliability Standards of the ERO and the Regional Entity within which it is located.”)

frequency set points, and time delays) for implementation by UFLS entities within its area that meets the specified minimum requirements. Without addressing Requirement R2 specifically, the Commission proposed to approve regional Reliability Standard PRC-006-SERC-01 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

Comments

27. MISO states that PRC-006-SERC-01 is overly prescriptive and may not allow planning coordinators the flexibility needed to ensure reliability. MISO states that Requirements R2.3, R2.4, R2.5, and R2.6 specify acceptable ranges and limits for the UFLS design. MISO states that PRC-006-SERC-01 makes no provision to accommodate a planning coordinator's determination that the best performing design does not fall within the specified set points and ranges in the regional Reliability Standard, which MISO acknowledges reflect historical practice. MISO states that there may be sound technical reasons to deviate from the prescribed set points. MISO also states that these set points could frustrate coordination with systems that deviate from the PRC-006-SERC-01 without regard to the reliability benefits of deviating from historical practice.

28. In responsive comments, SERC states that MISO's comments are outside the scope of the comments sought in the NOPR. SERC also states that MISO participated in the standard development process for PRC-006-SERC-01 and provided comments similar to those offered here (i.e., that Requirement R2 is too prescriptive and planning coordinators should not be restricted to the acceptable ranges and limits specified in Requirement R2). SERC notes that MISO acknowledged that the set points specified in

Requirement R2 reflect historical practice. SERC states that the standard drafting team responded to MISO's comments by pointing to the 18 different UFLS schemes in the SERC Region and by noting that Requirement R2 was "needed to ensure coordination and consistency among the UFLS schemes in SERC."²⁹ SERC states that MISO's comments were considered and rejected by the standard drafting team and that the Commission should likewise reject them.

Commission Determination

29. We reject MISO's protest that the acceptable ranges and limits for the UFLS design in Requirement R2 are overly prescriptive or do not afford planning coordinators sufficient flexibility. As noted in NERC's petition and the NOPR, regional Reliability Standard PRC-006-SERC-01 sets minimum automatic UFLS design requirements, which are equivalent to the design requirements in the SERC UFLS program that have been in effect since September 3, 1999.³⁰ Imposing uniform, minimum requirements on UFLS programs in the SERC Region necessarily limits the flexibility of planning coordinators and UFLS entities. However, based on the record before us, we find that the benefits of requiring minimum standards outweighs any loss in flexibility, particularly when those minimum standards are based on historical practices in SERC. Other than asserting the loss of flexibility, MISO does not question the ranges and limits in Requirement R2, or

²⁹ SERC Reply Comments at 3-4 (citing standard drafting team response).

³⁰ NOPR, 140 FERC ¶ 61,056 at P7 (citing NERC Petition at 12).

explain how they are not technically justified. In addition, MISO does not suggest alternate ranges and limits, other than to note that the Midwest Reliability Organization is “investigating the reliability benefits of setting the frequency set point blocks at less than 0.2 Hz apart to create finer system control.”³¹ While we reject MISO’s protest, we do not foreclose the possibility that NERC and SERC may wish to revise the ranges and limits in Requirement R2 at some future time based on changed circumstances or with added experience.

C. Violation Risk Factors, Violation Severity Levels, Implementation Plan, and Effective Date

30. In the NOPR, the Commission proposed to approve the violation risk factors, with one modification, violation severity levels, implementation plan, and effective date proposed by NERC. The NOPR proposed to direct NERC to modify the violation risk factor assigned to Requirement R6 from “medium” to “high” to make it consistent with the Commission’s VRF guidelines and the violation risk factor for Requirement R9 of NERC Reliability Standard PRC-006-1, since both Requirements address a similar reliability goal.

Comments

31. NERC and SERC state that they do not oppose the Commission’s proposal to direct modification of the violation risk factor for Requirement R6 from “medium” to “high.”

³¹ MISO Comments at 2.

Commission Determination

32. The Commission directs NERC and SERC to modify the violation risk factor for regional Reliability Standard PRC-006-SERC-01, Requirement R6, from “medium” to “high.” NERC and SERC are directed to submit the revised violation risk factor within 30 days of the effective date of this final rule. The Commission approves the remaining violation risk factors, violation severity levels, implementation plan, and effective date proposed by NERC.

III. Information Collection Statement

33. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping requirements (collections of information) imposed by an agency.³² Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this 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.

34. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of Paperwork Reduction Act of 1995.³³ The Commission solicited comments on the need for and the purpose of the information contained in regional Reliability Standard PRC-006-SERC-01 and the

³² 5 CFR 1320.11.

³³ 44 U.S.C. 3507(d)

corresponding burden to implement the regional Reliability Standard. The Commission received comments on specific requirements in the regional Reliability Standard, which we address in this final rule. However, the Commission did not receive any comments on our reporting burden estimates.

35. This final rule approves regional Reliability Standard PRC-006-SERC-01. This is the first time NERC has requested Commission approval of this regional Reliability Standard. NERC states in its petition that UFLS requirements have been in place at a continent-wide level and within SERC for many years prior to implementation of the Commission-approved Reliability Standards in 2007. Because the UFLS requirements have been in place prior to the development of PRC-006-SERC-01, the regional Reliability Standard is largely associated with requirements that applicable entities are already following.³⁴ Regional Reliability Standard PRC-006-SERC-01 is designed to ensure that automatic UFLS protection schemes, designed by planning coordinators and implemented by applicable distribution providers and transmission owners in the SERC Region, are coordinated so they may effectively mitigate the consequences of an underfrequency event. The regional Reliability Standard is only applicable to generator owners, planning coordinators, and UFLS entities in the SERC Region. The term “UFLS

³⁴ See 5 CFR 1320.3(b)(2) (“The time, effort, and financial resources necessary to comply with a collection of information that would be incurred by persons in the normal course of their activities (e.g., in compiling and maintaining business records) will be excluded from the ‘burden’ if the agency demonstrates that the reporting, recordkeeping, or disclosure activities needed to comply are usual and customary.”).

entities” means all entities that are responsible for the ownership, operation, or control of automatic UFLS equipment as required by the UFLS program established by the planning coordinators. Such entities may include distribution providers and transmission owners. The reporting requirements in regional Reliability Standard PRC-006-SERC-01 only pertain to entities within the SERC Region.

36. Public Reporting Burden: Our estimate below regarding the number of respondents is based on the NERC compliance registry as of May 29, 2012. According to the NERC compliance registry, there are 21 planning coordinators and 104 generator owners within the SERC Region. The individual burden estimates are based on the time needed for planning coordinators to incrementally gather data, run studies, and analyze study results to design or update the UFLS programs that are required in the regional Reliability Standard in addition to the requirements of the NERC Reliability Standard PRC-006-1.³⁵ Additionally, generator owners must provide a detailed set of data and documentation to SERC within 30 days of a request to facilitate post event analysis of frequency disturbances. These burden estimates are consistent with estimates for similar tasks in other Commission-approved Reliability Standards.

³⁵ The burden estimates for Reliability Standard PRC-006-1 are included in Order No. 763 and are not repeated here.

PRC-006-SERC-01 (Automatic Underfrequency Load Shedding Requirements) ³⁶	Number of Respondents Annually (1)	Number of Responses per Respondent (2)	Average Burden Hours Per Response (3)	Total Annual Burden Hours (1)x(2)x(3)
PCs*: Design and document Automatic UFLS Program	21	1	8	168
PCs: Provide Documentation and Data to SERC			16	336
GOs*: Provide Documentation and Data to SERC	104	1	16	1,664
GOs: Record Retention			4	416
Total				2,584

*PC=planning coordinator; GO=generator owner

Total Annual Hours for Collection: (Compliance/Documentation) = 2,584 hours.

Total Reporting Cost for planning coordinators: = 504 hours @ \$120/hour = \$60,480.

Total Reporting Cost for generator owners: = 1,664 hours @ \$120/hour = \$199,680.

Total Record Retention Cost for generator owners: 416 hours @ \$28/hour = \$11,648.

Total Annual Cost (Reporting + Record Retention)³⁷: = \$60,480 + \$199,680 + \$11,648 = \$271,808.

Title: Mandatory Reliability Standards for the SERC Region

Action: Proposed Collection FERC-725K.

³⁶ Regional Reliability Standard PRC-006-SERC-01 applies to planning coordinators, UFLS entities and generator owners. However, the burden associated with the UFLS entities is not new because it was accounted for under Commission-approved Reliability Standards PRC-006-1.

³⁷ The hourly reporting cost is based on the cost of an engineer to implement the requirements of the rule. The record retention cost comes from Commission staff research on record retention requirements.

OMB Control No.: 1902-0260.

Respondents: Businesses or other for-profit institutions; not-for-profit institutions.

Frequency of Responses: On Occasion.

Necessity of the Information: This final rule approves the regional Reliability Standard pertaining to automatic underfrequency load shedding. The regional Reliability Standard helps ensure the reliable operation of the Bulk-Power System by arresting declining frequency and assisting recovery of frequency following system events leading to frequency degradation.

Internal Review: The Commission has reviewed the regional Reliability Standard and made a determination that its action is necessary to implement section 215 of the FPA. These requirements, if accepted, should conform to the Commission's expectation for UFLS programs as well as procedures within the SERC Region.

37. 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].

38. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oir_submission@omb.eop.gov.

Comments submitted to OMB should include Docket Number RM12-09 and an OMB Control Number 1902-0260.

IV. Environmental Analysis

39. 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.³⁸ 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.³⁹ The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

40. The Regulatory Flexibility Act of 1980 (RFA)⁴⁰ generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business

³⁸ Regulations Implementing the National Environmental Policy Act, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986-1990 ¶ 30,783 (1987).

³⁹ 18 CFR 380.4(a)(2)(ii).

⁴⁰ 5 U.S.C. 601-612.

Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.⁴¹ The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.⁴²

41. Regional Reliability Standard PRC-006-SERC-01 establishes consistent and coordinated requirements for the design, implementation, and analysis of automatic UFLS schemes among all applicable entities within the SERC Region. It is applicable to planning coordinators, generator owners and entities that are responsible for the ownership, operation, or control of UFLS equipment. Comparison of the NERC Compliance Registry with data submitted to the Energy Information Administration on Form EIA-861 indicates that perhaps as many as 1 small entity is registered as a planning coordinator and 5 small entities are registered as generator owners in the SERC Region. The Commission estimates that the small planning coordinator to whom the proposed regional Reliability Standard will apply will incur compliance costs of \$2,880 (\$2,880 per planning coordinator) associated with the regional Reliability Standard's requirements. The small generator owners will incur compliance and record keeping costs of \$10,160 (\$2,032 per generator owner). Accordingly, regional Reliability Standard PRC-006-

⁴¹ 13 CFR 121.101.

⁴² 13 CFR 121.201, Sector 22, Utilities & n.1.

SERC-01 should not impose a significant operating cost increase or decrease on the affected small entities.

42. Further, NERC explains that the cost for smaller entities to implement regional Reliability Standard PRC-006-SERC-01 was considered during the development process. The continent-wide NERC UFLS Reliability Standard PRC-006-1 requires a planning coordinator to identify which entities will participate in its UFLS scheme, including the number of steps and percent load that UFLS entities will shed. The standard drafting team recognized that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance. Therefore, the standard drafting team included Requirement R5, which states that such small entities shall not be required to have more than one UFLS step, and sets their implementation tolerance to a wider level. Requirement R5 limits additional compliance costs for smaller entities to comply with the regional Reliability Standard.

43. Based on this understanding, the Commission certifies that regional Reliability Standard PRC-006-SERC-01 will not have a significant economic impact on a substantial number of small entities. Accordingly, no regulatory flexibility analysis is required.

VI. Document Availability

44. 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.

45. 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.

46. 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

47. These regulations are effective [insert date 60 days from the date the rule is published 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.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

141 FERC ¶ 61,241
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony T. Clark.

North American Electric Reliability Corporation

Docket No. RR12-8-000

ORDER CONDITIONALLY APPROVING REVISIONS TO NORTH AMERICAN
ELECTRIC RELIABILITY CORPORATION RULES OF PROCEDURE

(Issued December 20, 2012)

1. On May 7, 2012, the North American Electric Reliability Corporation (NERC) submitted a petition requesting approval of revisions to the NERC Rules of Procedure and its Appendices. Pursuant to section 215(f) of the Federal Power Act (FPA), we conditionally approve the proposed revisions to the Rules of Procedure, with limited exceptions.¹ As discussed in the body of this order, we direct NERC to make a compliance and an informational filing within 60 days of the date of this order.

I. Background

A. EPAAct 2005 and Mandatory Reliability Standards

2. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which provide for the reliable operation of the Bulk-Power System, subject to Commission review and approval.² On February 3, 2006, the Commission issued Order No. 672 to

¹ 16 U.S.C. § 824(f) (2006).

² *Id.* § 824o(d)(2).

implement the requirements of section 215 of the FPA governing electric reliability.³ In July 2006, the Commission certified NERC as the ERO.⁴

3. Section 215(f) of the FPA states that the ERO “shall file with the Commission for approval any proposed rule or proposed rule change, accompanied by an explanation of its basis and purpose.”⁵ Section 215(f) further provides that a “proposed rule or proposed rule change shall take effect upon a finding by the Commission, after notice and opportunity for comment, that the change is just, reasonable, not unduly discriminatory or preferential, is in the public interest, and satisfies the requirements of subsection (c).”⁶

B. NERC Petition

4. On May 7, 2012, NERC filed a petition requesting approval of revisions to provisions in Sections 300 (Reliability Standards Development), 400 (Compliance Enforcement), 600 (Personnel Certification), 800 (Reliability Assessment and Performance Analysis), 1000 (Situation Awareness and Infrastructure Security), 1400 (Amendments to the Rules of Procedure), and 1700 (Challenges to Determinations) of the NERC Rules of Procedure. The petition also sought to revise NERC Rules of Procedure Appendices 2 (Definitions), 3C (Procedure for Coordinating Reliability Standards Approvals, Remands, and Directives), 4B (Sanction Guidelines), 4C (Uniform Compliance Monitoring and Enforcement Program (CMEP)), 5B (Statement of Compliance Registry Criteria), and 6 (System Operator Certification Program Manual).

5. NERC states that the proposed revisions are the result of a “wide-ranging, comprehensive review of the ROP [Rules of Procedure] and was conducted to identify improvements to the underlying processes reflected in the ROP based on the experience to date of NERC and the Regional Entities ... [and] to further implement actions identified in 2009 in NERC’s Three-Year ERO Performance Assessment Report, to

³ *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 (2006), *order on reh’g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

⁴ *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).

⁵ 16 U.S.C. § 824o(f).

⁶ *Id.*

eliminate inconsistencies, and to make other improvements and clarifications identified by the review teams.”⁷

II. Notices of Filings and Responsive Pleadings

6. Notice of NERC’s petition was published in the Federal Register, 77 Fed. Reg. 28,593 (2012), with interventions and protests due on or before May 29, 2012. Modesto Irrigation District timely filed a motion to intervene. ISO/RTO Council filed a timely motion to intervene and comment. Motions to intervene and protests were timely filed by Occidental Energy Ventures Corp. (OEVC), Midwest Independent Transmission System Operator, Inc. (MISO), and jointly by American Public Power Association, Edison Electric Institute, Electric Consumers Resource Council, Electric Power Supply Association, and National Rural Electric Cooperative Association (collectively, Trade Associations).

7. On May 30, 2012, the Trade Associations filed a corrected motion to intervene and protest. On May 31, 2012, ISO/RTO Council filed an amended motion to intervene and comments. On June 7, 2012, NERC filed a motion to answer the Trade Associations and OEVC protests. On June 14, 2012, ISO/RTO Council filed a motion to answer the OEVC protest. On June 21, 2012, OEVC filed a motion to answer the ISO/RTO Council’s June 14, 2012 answer.

III. Procedural Matters

8. Pursuant to Rule 214 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2012), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

9. Rule 213(a)(2) of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2012), prohibits an answer to a protest or answer, unless otherwise ordered by the decisional authority. We will accept NERC, ISO/RTO Council, and OEVC’s answers because they have provided information that assisted us in our decision-making process.

IV. Discussion

10. Except as otherwise indicated below, the Commission approves NERC’s proposed revisions to the NERC Rules of Procedure and Appendices. Pursuant to section 215(f) of the FPA, we find that the proposed revisions we approve are just, reasonable, not unduly discriminatory or preferential, and in the public interest and that they satisfy the

⁷ NERC Petition at 1 (citing North American Electric Reliability Corporation, Report, Docket No. RR09-7-000 (filed July 20, 2009)).

requirements of section 215(c) of the FPA. These proposed revisions are an improvement over the currently effective NERC Rules of Procedure in that they reflect NERC's accumulated experience, changes in program area processes, Commission orders, stakeholder concerns, and actions or changes identified in the three-year ERO performance assessment process or in renegotiation of the Regional Entity delegation agreements.

A. NERC Proposed Revisions to Section 300 (Reliability Standards Development)

11. NERC proposes numerous revisions to Section 300.⁸ We address below NERC's proposed revisions to Sections 317 and 318.

1. Section 317

12. With respect to Section 317, which currently requires NERC to conduct at least a five-year review of NERC's Reliability Standards, NERC proposes the following revisions:

NERC shall complete a review of each Reliability Standard at least once every five years, or such longer period as is permitted by the American National Standards Institute, from the effective date of the Reliability Standard or the latest revision to the Reliability Standards, whichever is later.⁹

13. NERC states that while the current language was meant to satisfy the American National Standards Institute's (ANSI) accreditation requirements, "it may be possible to obtain relief from ANSI concerning the requirement that each Reliability Standard be reviewed at least once every five years."¹⁰

Comments

14. MISO states that the Commission should reject the proposed revision to Section 317. MISO states that the Reliability Standards "need more consistent review and adjustment than would be permitted under the NERC proposal ... [and that] there is still

⁸ NERC proposes revisions to Sections 304-309, 311-313, 315-320.

⁹ In this order, when reproducing the proposed text, underlined text reflects language NERC proposes to add and strikethrough text reflects language NERC proposes to delete.

¹⁰ NERC Petition at 8.

substantial redundancy in many of the Reliability Standards, and a more regular schedule of review would have a positive impact on the administration of and compliance with the Reliability Standards.”¹¹ Further, MISO states that, in addition to keeping the requirement that NERC conduct a review of each Reliability Standard at least once every five years, the Commission should require NERC to conduct a periodic review, at least every five years, “of the entire set of Reliability Standards, and the manner in which they fit together, for potential improvements.”¹²

Commission Determination

15. We approve NERC’s proposed revision to Section 317 and reject MISO’s protest. The proposed revision to Section 317 does not eliminate the Reliability Standard review requirement currently imposed on NERC. Instead, the proposed revision introduces some flexibility in determining the schedule for such reviews. NERC states that the five-year schedule in the current language was meant to satisfy ANSI accreditation but otherwise carries no special significance. We find that revising Section 317 to allow for a longer review schedule is acceptable to the extent it affords NERC some flexibility in scheduling its Reliability Standard reviews. Contrary to MISO’s protest, the potential change in scheduling of such reviews does not alter the substance of NERC’s reviews. Further, we do not deem it appropriate in this case to adopt MISO’s suggestion that we direct additional review requirements.¹³

2. Section 318

16. Section 318 addresses Coordination with the North American Energy Standards Board (NAESB), with NERC proposing the following revisions:

¹¹ MISO Protest at 6.

¹² *Id.*

¹³ In addition to the reviews required by Section 317, other avenues are available for MISO to pursue its concerns. For example, NERC is currently reviewing existing Reliability Standard requirements to identify those that provide little protection to the reliable operation of the bulk electric system, are redundant or unnecessary, or those whose removal would increase the efficiency of NERC’s compliance programs. See Project 2013-02: Paragraph 81 website, *available at* http://www.nerc.com/filez/standards/Project201302_Paragraph_81.html. NERC initiated this project in response to the Commission’s FFT Order. *North American Electric Reliability Corp.*, 138 FERC ¶ 61,193, at P 81 (FFT Order), *order on clarification*, 139 FERC ¶ 61,168 (2012).

NERC shall, ~~through a memorandum of understanding,~~ maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

NERC states that the reference to the “memorandum of understanding” is being deleted because the memorandum became “unnecessary and has been terminated, with other working mechanisms established with the NAESB and the ISO/RTO Council.”¹⁴

Comments

17. MISO states that Section 318, as revised, is vague and “virtually meaningless.” MISO contends that “the ISO/RTO Council represents many of the key operators of the Bulk Electric System in the United States, and its members’ experiences with the Reliability Standards, as well as their input into potential changes to both the standards and enforcement practices, have significant value for the administration of the reliability regulatory mechanism under Federal Power Act Section 215.”¹⁵ MISO maintains that NERC should be “required not only to have a close working relationship with the ISO/RTO Council, but also to have more formalized processes in place to receive and consider the input of the ISO/RTO Council.”¹⁶

Commission Determination

18. We approve NERC’s proposed revision to Section 318. We reject the assertion that elimination of the “memorandum of understanding” reference in Section 318 implies that NERC is not committed to working with the ISO/RTO Council. NERC states that elimination of the reference from Section 318 is due to the termination of the “memorandum of understanding” and reiterates that it will “continue to maintain close working relationships with the NAESB and the ISO/RTO Council to coordinate wholesale electric business standards and market protocols with NERC Reliability Standards.”¹⁷ Given that Section 318 still requires NERC to “maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council,” the Commission declines to require NERC to develop any “formalized processes” beyond

¹⁴ NERC Petition at 8.

¹⁵ MISO Protest at 6-7.

¹⁶ *Id.*

¹⁷ NERC Petition at 8.

what is already available to interested entities or what NERC and NAESB or ISO/RTO Council otherwise may agree upon.

B. NERC Proposed Revisions to Section 400 (Compliance Enforcement)

19. NERC proposes numerous revisions to Section 400.¹⁸ We address below NERC's proposed revisions to Sections 401.8, 402.5, 402.6, 403.6, 403.10.5, 403.15, 408.1, 409.1, 409.3, 412, and 413.

1. Section 401.8

20. In Section 401.8, which currently provides that registered entities will not be subject to multiple enforcement actions by NERC and a Regional Entity, NERC proposes the following revisions:

Multiple Enforcement Actions – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

21. NERC states that a registered entity should not be subject to an enforcement action by more than one Regional Entity for the same violation unless the registered entity “is registered, and the violation occurred, in more than one Region.”¹⁹

Comments

22. MISO states that it “appears that what NERC intends here is that a registered entity, under no circumstances, should be subject to multiple enforcement actions for the same violation, and should only be subject to enforcement actions by multiple Regional Entities when they are engaged in a joint enforcement action in circumstances where a violation has occurred in more than one Regional Entity ... [and that] this is the only reasonable interpretation of the revised language.”²⁰ MISO states that the Commission should “clarify that Section 401.8 is to be read to prohibit multiple enforcement actions always and under all circumstances, and to allow more than one Regional Entity to engage in an enforcement action of a registered entity for the same violation only where such Regional Entities are coordinating on a joint enforcement action. In the absence of

¹⁸ NERC proposes revisions to Sections 401-403, 407-409, 412-414.

¹⁹ NERC Petition at 10.

²⁰ MISO Protest at 7.

such a clarification, the Commission should remand this proposed procedural change to NERC for further revision.”²¹

Commission Determination

23. We approve NERC’s proposed revision to Section 401.8 and agree that a registered entity should not be subject to an enforcement action by more than one Regional Entity for the same violation, unless the registered entity is registered and the violation occurred in more than one Regional Entity. We reject MISO’s request that we interpret Section 401.8 to “allow more than one Regional Entity to engage in an enforcement action of a registered entity for the same violation only where such Regional Entities are coordinating on a joint enforcement action.” The proposed revision to Section 401.8 imposes no such requirement. We also reject MISO’s request that we remand this provision to NERC to make that point explicit. While we agree with MISO that there could be efficiencies in conducting joint enforcement actions when a registered entity has committed the same violation in two Regional Entities in which it is registered, MISO does not explain why joint enforcement actions should be required. There may be sound reasons for not conducting a joint enforcement action and, because of that, we will not foreclose that option to the affected Regional Entities.

2. Section 402.5

24. In Section 402.5, which addresses “Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives,” NERC proposes the following revisions:

Remedial Action Directives may be issued by NERC or a Regional Entity that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat.

25. NERC states that the revisions to Section 402.5, as to when a Remedial Action Directive may be issued, is intended to make that provision consistent with the proposed revision to the definition of “Remedial Action Directive” in Appendix 2 of the NERC Rules of Procedure.²²

²¹ *Id.* at 8.

²² As proposed in Appendix 2, the revised definition of Remedial Action Directive is: “an action (other than a Penalty or sanction) required by a Compliance Enforcement

Comments

26. MISO states that the proposed revisions “would allow the issuance of a Remedial Action Directive in circumstances not only where an entity is engaging in a particular act, but also where it is about to engage in an act that might result in non-compliance with a Reliability Standard (and where the reliability of the Bulk Electric System is under threat).”²³ MISO states that, while it does not question the need for such directives under the appropriate circumstances, they should be “appropriately constrained by processes and procedures to ensure that such directives are issued appropriately, and that they facilitate reliability.”²⁴

Commission Determination

27. We approve NERC’s proposed revision to Section 402.5. MISO misapprehends the proposed revision to Section 402.5, which currently allows for the issuance of Remedial Action Directives when an entity is “about to engage in an act or practice that would result in noncompliance with a Reliability Standard” and there is an “imminent” threat to the Bulk-Power System. Under the proposed revision, a Remedial Action Directive could issue when an entity is engaged in or is about to engage in such an act and there is an imminent or actual threat to the Bulk-Power System.

3. Section 402.6

28. Currently effective Section 402.6, which is the “Due Process” subsection of the section addressing “NERC Oversight of the Regional Entity Compliance Monitoring and Enforcement Programs,” provides that:²⁵

The appeals process will also allow for appeals to NERC of any findings of noncompliance issued by NERC to a Regional Entity for Reliability Standards and Requirements where the Regional Entity is monitored for compliance to a Reliability Standard. No monetary Penalties will be levied

Authority that (1) is to bring a Registered Entity into compliance with a Reliability Standard or to avoid a Reliability Standard violation, and (2) is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat.”

²³ MISO Protest at 10.

²⁴ *Id.*

²⁵ NERC, in its petition, does not propose revisions to either Sections 402.6 or 404.1 of the NERC Rules of Procedure.

in these matters; however sanctions, remedial actions, and directives to comply may be applied by NERC.

29. Section 404.1 of the Rules of Procedure, which is the “NERC Obligations” subsection of the section addressing “NERC Monitoring of Compliance for Regional Entities or Bulk Power Owners, Operator, or Users,” provides in relevant part that:

NERC shall evaluate compliance and noncompliance with all of the Reliability Standards that apply to the Regional Entities and shall impose sanctions, Penalties, or Remedial Action Directives when there is a finding of noncompliance.

30. In Appendix 2 to the Rules of Procedure, which includes the “Definitions Used in the Rules of Procedure,” “Penalty” is defined in relevant part as “all penalties and sanctions, including but not limited to a monetary or non-monetary penalty.”

Commission Determination

31. Currently effective Sections 402.6 and 404.1 appear to conflict as to whether Regional Entities can be assessed monetary penalties for non-compliance with a Reliability Standard. While Section 402.6 appears to prohibit monetary penalties, Section 404.1 would seem to allow for monetary penalties. Pursuant to section 215(f) of the FPA, the Commission directs NERC, in an informational filing due within 60 days of this order, to clarify whether NERC may assess monetary penalties against Regional Entities for a violation of a Reliability Standard and, to the extent NERC agrees that there is an inconsistency between the cited sections in the Rules of Procedure, to explain how it proposes to address the inconsistency.²⁶

4. Sections 403.6 and 403.10.5

32. In Sections 403.6 and 403.10.5, which address the submission of Mitigation Plans, NERC proposes the following revisions:

6. Regional Entity Compliance Staff Independence — The Regional Entity Compliance Staff shall be capable of and required to make all determinations of compliance and noncompliance and determine Penalties, sanctions, and Remedial Action Directives and to review and accept Mitigation Plans and other Mitigating Activities.

²⁶ This is an informational filing only and will not be noticed or subject to comments.

10.5 A Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan with a timeline addressing how the noncompliance will be corrected, unless an enforcement process is used that does not require a Mitigation Plan. The Regional Entity Compliance Staff shall review and ~~approve~~ accept the Mitigation Plan in accordance with Appendix 4C.

33. NERC states that the revision to Section 403.6 is meant to reflect “that not all actions taken by a Registered Entity to correct and prevent recurrence of a noncompliance are embodied in a Mitigation Plan (i.e., “Mitigating Activities”).”²⁷ NERC states that the revision to Section 403.10.5 is necessary because NERC has adopted enforcement process options that do not require a registered entity to submit a formal Mitigation Plan.²⁸

Commission Determination

34. We conditionally approve NERC’s proposed revisions. We agree with NERC that a formal Mitigation Plan may not be necessary in all cases of possible noncompliance because CMEP Section 6.1 only requires the filing of a Mitigation Plan by a registered entity “found to be in violation of a Reliability Standard.” Thus, Mitigating Activities other than Mitigation Plans could apply to nearly all possible violations, with only a small number of Mitigation Plans filed, reviewed by the Regional Entities and NERC before they become effective, and submitted to the Commission pursuant to CMEP Section 6.0.

35. We believe a streamlined approach to mitigation may more quickly and efficiently ensure compliance with Reliability Standards and the reliability of the Bulk-Power System in some situations. The proposed definition of Mitigating Activities nevertheless encompasses all activities to correct and prevent recurrence of noncompliance. The definition does not itself include any concept of documentation, review, or auditing to assess the efficacy of Mitigating Activities outside of the provisions of CMEP Section 6.0 that apply only to Mitigation Plans. While NERC indicates in proposed revisions to specific CMEP provisions that a Compliance Enforcement Authority can review the adequacy and completion of Mitigating Activities, only one of these revisions provides

²⁷ NERC Petition at 11. NERC Rules of Procedure, Appendix 2 (Definitions) defines “Mitigating Activities” as “actions taken by a Registered Entity to correct and prevent recurrence of a noncompliance, whether or not the actions are embodied in a Mitigation Plan.”

²⁸ *Id.* at 12.

any detail about such efforts. In that revision, to CMEP Section 3.1.4.3 relating to compliance audits, NERC proposes that an audit “may include a review of any Mitigating Activities which the Registered Entity has not yet completed.” This proposal would appear to exclude consideration of possible violations for which a Mitigating Activity had been completed.

36. One of the highest priorities of NERC’s CMEP should be adequate and timely mitigation of possible violations so as to return a registered entity to compliance and minimize or prevent future similar violations. A streamlined approach to mitigation must provide controls to ensure that Mitigating Activities are sufficient and timely completed. There also must be sufficient tracking of Mitigating Activities so that they may be audited or otherwise reviewed as NERC proposes in CMEP Section 3.1.4.3 and other CMEP provisions, both as to completed and uncompleted Mitigating Activities.

37. In this regard, we note that NERC indicated in its FFT filing that it would apply a tracking number to what it termed “mitigation activities” regarding possible violations treated as FFTs and that registered entities must “maintain evidence of such corrective actions for possible verification through an audit, spot check, random sampling or other inquiry.”²⁹ This proposal applied only to possible violations that posed a lesser risk to Bulk-Power System reliability, so additional attention may be warranted as to the scope, completion, and review of Mitigating Activities that could be applied to more serious possible violations. Therefore, we direct NERC to submit a compliance filing within 60 days of this order in which it explains how it and Regional Entities will assess the adequacy and completion of Mitigating Activities on a timely basis, including at least the tracking and review mechanisms to which NERC committed in the FFT filing and that the Commission recognized in the FFT Order.

5. Sections 403.15, 408.1, and 409.1

38. In Sections 403.15, 408.1, and 409.1, which address appeals of enforcement actions, NERC proposes the following revisions that would allow Regional Entities to appeal decisions of Regional Entity Hearing Bodies:

[403.15] ... The Regional Entity hearing process shall be conducted before the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. ... If a Bulk Power System owner, operator, or user or a Regional Entity has completed the Regional Entity

²⁹ FFT Order, 138 FERC ¶ 61,193, at P 14. The Commission recognized these mechanisms in approving the FFT proposal with limited conditions. *Id.* P 57.

hearing process and desires to appeal the outcome of the hearing, the Bulk Power System owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

[408.1] Scope of Review — A Registered Entity or a Regional Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity Compliance Monitoring and Enforcement Program audit finding, may do so by filing a notice of the challenge with NERC's ~~D~~director of ~~Compliance~~ enforcement no later than 21 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Regional Entity Hearing Bodies shall be pursuant to Section 409.

[409.1] Time for Appeal — A Regional Entity acting as the Compliance Enforcement Authority, or an owner, operator or user of the Bulk Power System, wishing shall be entitled to appeal from a final decision of a Regional Entity Hearing Body concerning that finds an Alleged ~~✗~~Violation of a Reliability Standard, ~~or imposes a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, shall file its by filing a~~ notice of appeal with NERC's ~~D~~director of ~~Compliance~~ enforcement, ~~with a copy~~ copies to the Regional Entity and any other Participants in the Regional Entity Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Regional Entity Hearing Body

39. NERC states that allowing Regional Entities acting as Compliance Enforcement Authorities to appeal Regional Entity Hearing Body decisions to NERC is “warranted because as the Regional Entity hearing process has evolved over time ... the Hearing Bodies are not extensions of the Regional Entity Compliance Program, but rather are independent tribunals with separation of functions from the Compliance Program, conducting due process hearings and rendering decisions.”³⁰ NERC further states that the proposed revision allows NERC to fulfill its “ultimate responsibility for the correctness

³⁰ NERC Petition at 14.

and consistency of decisions on compliance matters” by instituting a process whereby NERC can review potentially erroneous Hearing Body decisions that are favorable to the registered entity.³¹

Comments

40. The Trade Associations, MISO, and OEVC state that the Commission should reject the proposed revisions to the NERC Rules of Procedure allowing Regional Entities to appeal decisions of the Regional Entity Hearing Bodies.

41. The Trade Associations protest these revisions because they “would unnecessarily change the enforcement balance now in effect under the [NERC Rules of Procedure] and [are] inconsistent with the spirit of section 215 ... and 18 C.F.R. § 39.7.”³² The Trade Associations state that, while section 215 and the Commission’s regulations contemplate that the entity to which the penalty would apply can appeal, neither contemplate allowing the Regional Entity to appeal. The Trade Associations contend that the present system provides “appropriate due process while ensuring a reasonably speedy and final result.”³³ The Trade Associations further contend that a Hearing Body may not be sufficiently independent from the Regional Entity so as to warrant providing the Regional Entity with an independent right to appeal.

42. MISO protests that a new right of appeal “potentially subjects registered entities to extended and repeated enforcement actions for the same violation, even where they have been exonerated by an independent Regional Entity Hearing Body.”³⁴ MISO contends that there are other ways for NERC to ensure consistency. MISO cites using certified questions submitted to the NERC Board of Trustees Compliance Committee under proposed Section 412 and NERC’s authority under proposed Section 413 to review Regional Entity Hearing Body final decisions that are not appealed.

43. OEVC protests that giving Regional Entities the right to appeal is inconsistent with Section 403.15 because it would not make the Regional Entity Hearing Board “the final adjudicator at the Regional Entity level.” OEVC contends that allowing a Regional Entity to appeal eliminates the value of the hearing process at the Regional Entity level because it would allow the Regional Entity to appeal what are effectively its own decisions, infringing the due process rights of registered entities and wasting resources.

³¹ *Id.*

³² Corrected Trade Associations Protest at 5.

³³ *Id.* at 6.

³⁴ MISO Protest at 8.

OEVC further contends that the Regional Entity Hearing Body is not a wholly “independent tribunal” because its authority stems directly from delegated power from NERC and/or the Regional Entity.

Commission Determination

44. We approve NERC’s proposed revisions granting Regional Entities a right to appeal Regional Entity Hearing Body decisions. We agree with NERC that there should be an appellate mechanism by which NERC can review potentially erroneous Hearing Body decisions that are favorable to a registered entity.

45. The protests support maintaining the current system by which Regional Entity compliance staff cannot appeal the decisions of Regional Entity Hearing Bodies. With the exception of MISO, however, the protests do not explain how potentially erroneous decisions made by Regional Entity Hearing Bodies benefiting registered entities can be corrected, particularly if the possible error resulted in a finding of no violation when a violation actually occurred.³⁵ The protests, instead, claim that the proposed revisions would adversely affect the due process rights of registered entities, impose new costs and administrative burdens, and are inconsistent with the spirit of section 215, the Commission’s regulations, and the NERC Rules of Procedure.

46. We reject the assertion that affording Regional Entities the right of appeal is inconsistent with the spirit of section 215, the Commission’s regulations implementing section 215, or the NERC Rules of Procedure. The Trade Associations state that, while “the statute [section 215(e)] and the Commission’s regulation [18 C.F.R. § 39.7(e)(1)] clearly contemplate that the entity to which the penalty would apply can appeal a NERC decision, neither of these provisions contemplate the appeal by a Regional Entity of a finding by its own Hearing Body that no penalty should be applied.” While the Trade Associations are correct that the cited provisions do not explicitly afford a right of appeal to Regional Entities, those provisions do not preclude a Regional Entity right of appeal

³⁵ MISO contends that newly-proposed Sections 412 and 413, discussed *infra*, which, respectively, allow Regional Entity Hearing Bodies to submit certified questions to the NERC Board of Trustees Compliance Committee and allow NERC to review all Regional Entity Hearing Body final decisions, ensure consistent interpretation and enforcement of Reliability Standards without giving Regional Entities the right to appeal. While these new tools should help to ensure consistent interpretation and enforcement of Reliability Standards, we agree with NERC that they are not the same as an appellate process wherein the registered entity and Regional Entity could “present their respective positions and arguments as to the correctness of the Hearing Body decision and as to any errors that, it is contended, were made by the Hearing Body.” NERC Petition at 15 n.5.

either.³⁶ Indeed, for example, allowing an opportunity to correct a potentially erroneous decision of “no violation” by a Regional Entity Hearing Body is consistent with – and certainly does not offend – FPA section 215(e) and its focus on addressing Reliability Standard violations. We also reject OEVC’s assertion that the proposed revisions are inconsistent with revised Section 403.15 of the NERC Rules of Procedure because, if Regional Entities are given the right to appeal, the Regional Entity Hearing Bodies will no longer be “the final adjudicator at the Regional Entity level.” This assertion fails to grasp the difference between the role of the Regional Entity Hearing Body, which is effectively a trial body, and any appeal taken from the Regional Entity Hearing Body to NERC, which is appellate in nature in this instance. In this way, the Regional Entity Hearing Body remains the final adjudicator at the Regional Entity level (i.e., trial level), even if its final decision may be changed on appeal by NERC.

47. With respect to the due process claim, the protests do not explain how a Regional Entity’s right to appeal Regional Entity Hearing Board final decisions to NERC offends due process. An appeal by a Regional Entity is not, as MISO contends, an “extended and repeated enforcement action[] for the same violation, even where they have been exonerated by an independent Regional Entity Hearing Body.” Rather, it is an appellate review process in which NERC, not the Regional Entity, determines whether an independent Regional Entity Hearing Body’s final decision can be upheld based on the record compiled by the Regional Entity Hearing Body.³⁷ We also reject the Trade Associations’ unproven assertion that “the Regional Entity’s organizational link to, and familiarity with, NERC would dispose NERC to weigh the Regional Entity’s views more heavily than those of the Registered Entity.” The Commission operates from the premise that NERC will carry out its obligations under the NERC Rules of Procedure fairly and without bias. Nothing in the Trade Associations’ protest leads us to conclude otherwise.

48. NERC and the protesters also disagree as to the level of independence between the Regional Entities’ compliance staffs and the Regional Entity Hearing Bodies. The

³⁶ Section 215(e) of the FPA provides that “the ERO may impose ... a penalty on a user or owner or operator of the bulk-power system for a violation of a reliability standard approved by the Commission ... if the ERO, after notice and an opportunity for a hearing— (A) finds that the user or owner or operator has violated a reliability standard approved by the Commission ... and (B) files notice and the record of the proceeding with the Commission.”

³⁷ See Revised NERC Rules of Procedure Section 409.2 (“No factual material shall be presented in the appeal that was not first presented during the proceeding before the Regional Entity Hearing Body.”); revised Section 409.5 (“**Decision** – The Compliance Committee of the NERC Board of Trustees shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Regional Entity Hearing Body, the responses, and any reply filed with NERC.”).

protesters assert that a lack of independence makes it inappropriate for a Regional Entity that receives an adverse decision from a Regional Entity Hearing Body to appeal to NERC. Protesters do not provide adequate support for the claim that the Hearing Bodies lack independence. Moreover, revised Sections 403.15, 408.1, and 409.1 allow a Regional Entity to seek NERC review of a Regional Entity Hearing Body ruling against the Regional Entity. This circumstance runs counter to the assertion that the Regional Entity Hearing Body lacks independence. Rather, we agree with NERC that Regional Entity Hearing Bodies are “no longer extensions of the Regional Entity Compliance Program, but rather are independent tribunals with separation of functions from Compliance Program, conducting due process hearings and rendering decisions.”³⁸ As such, we find it is appropriate to have in place an appeal mechanism for Regional Entities when they believe that a Hearing Body decision is in error.

49. As for any new costs or administrative burdens resulting from Regional Entities having the right to appeal, we are satisfied that such costs or administrative burdens, to the extent they exist, are justified in the interest of ensuring that Reliability Standard violations are correctly addressed consistent with section 215(e).

6. Section 409.3

50. In Section 409.3, which addresses “Response to Notice of Appeal,” NERC proposes the following revisions:

~~Response to Notice of Appeal by Regional Entity — Within 21 days after the date receiving a copy of the notice of appeal is filed, the Regional Entity shall file the entire record of the matter~~ Regional Entity Hearing Body proceeding with NERC’s Director of Compliance enforcement, with a copy to the Registered Entity filing the notice, together with Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Regional Entity Hearing Body, other than the Participant filing the notice of appeal, shall file their ~~its~~ responses to the issues raised in the notice of appeal.

51. NERC states that the current requirement that the Regional Entity must provide a copy of the record to the appellant is deleted in the proposal because “all Participants should be expected to maintain their own copies of the record as it is compiled during the hearing.”³⁹

³⁸ NERC Petition at 14.

³⁹ *Id.* at 15.

Comments

52. MISO protests the elimination of the current requirement that the Regional Entity provide appellants with a copy of the record from the Hearing Body. MISO contends that eliminating this requirement and requiring the parties to maintain their own copies of the record is “highly unusual, and may affect a participant’s ability to receive a fair and impartial appeal.”⁴⁰ MISO states that the record in a Regional Entity Hearing Body proceeding should be maintained by the Regional Entity Hearing Body itself because it eliminates disputes about the record of the proceeding below and saves time and duplication of effort in compiling and keeping that record.

Commission Determination

53. We reject the proposed revision to Section 409.3 that eliminates the requirement that the Regional Entity provide a copy of the entire record of the Regional Entity Hearing Body proceeding to the registered entity that is a party to the appeal. NERC has not explained why the current practice should be altered other than to state that the parties before the Hearing Body should maintain their own copies. MISO further asserts that the record should be maintained by the Hearing Body because that eliminates any potential disputes about what constitutes the record and saves duplication of effort in compiling the record. However, we note that the proposed revision does not change who maintains the Hearing Body record, but whether the Regional Entity is required to provide a copy of the record to the registered entity.⁴¹

54. NERC is therefore directed to make a compliance filing within 60 days of the date of this order reinstating the provision that the Regional Entity provide a copy of the record to the registered entity.

7. Section 412

55. NERC proposes new Section 412 to establish procedures by which the NERC Board of Trustees Compliance Committee (BOTCC) will accept or reject a question certified to the BOTCC by a Regional Entity Hearing Body and, if the BOTCC accepts the certified question, the procedure for receiving argument and deciding the question. Section 412.1 states that a certified question is limited to a “significant question of law, policy or procedure the resolution of which may be determinative of the issues in the

⁴⁰ MISO Protest at 11.

⁴¹ NERC Rules of Procedure, Appendix 4C (Compliance Monitoring and Enforcement Program), Attachment 2 (Hearing Procedures), at Section 1.7.9 provides that “The Clerk shall maintain the record for all dockets.”

hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the Compliance Committee appropriate” Section 412.5 states that the “Compliance Committee’s decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.” NERC explains that this provision was added “to address stakeholder questions ... as to whether the BOTCC’s decision on a certified question in an individual proceeding would have precedential effect and thereafter be applicable to other compliance enforcement matters....”⁴²

Comments

56. MISO states that while it supports the use of certified questions to resolve important “questions of law, policy, or procedure,” the decisions of the BOTCC on submitted certified questions should have precedential effect. MISO states that “[m]aking decisions on certified questions broadly applicable would be of immense assistance in providing guidance and clarity to the industry as a whole ... [and the] Commission should require NERC to make resolutions of certified questions broadly applicable, instead of limiting the impact of such decisions to the proceedings in which they are issued.”⁴³ MISO further states that, although the proposed revision requires NERC to issue a written decision when it declines to address a certified question, the proposal does not explicitly require NERC to provide reasons for the denial. MISO states that the Commission should require NERC to explain its reasons for declining to answer a certified question.

Commission Determination

57. We approve new Section 412.⁴⁴ While there may be efficiencies in considering past BOTCC decisions to the extent that they are germane to a similar question posed to the BOTCC, we believe that it is within NERC’s prerogative to determine the precedential value of previous BOTCC decisions. Further, to date, there is very little experience with the Regional Entity hearing process. If future activity suggests that there is a need for greater consistency and clarity in the hearing process, NERC may want to reconsider the precedential value of BOTCC decisions. However, we believe that

⁴² NERC Petition at 21.

⁴³ MISO Protest at 9.

⁴⁴ The Commission approves, for the same reasons, the corresponding changes to Section 1.5.12, Certification of Questions to the NERC Board of Trustees, proposed in Appendix 4C, Attachment 2, Hearing Procedures.

Section 412 satisfies the statutory criteria for approval set forth in FPA section 215(f), and we are not persuaded by MISO's arguments otherwise.

58. Moreover, we reject MISO's request that we require NERC to explain its reasons for declining to answer certified questions. While the proposed revision does not explicitly require NERC to disclose its reasons for declining to answer a certified question, we are not persuaded that such a requirement is necessary.

8. Section 413

59. NERC proposes new Section 413 to provide that NERC shall review and process final decisions of Regional Entity Hearing Bodies concerning Alleged Violations, proposed Penalties or sanctions, or proposed Mitigation Plans that are not appealed pursuant to Section 409 as though the determination was made by the Regional Entity Compliance Program without a hearing to ensure consistency in determinations for similar facts and circumstances and among Regional Entities. Section 413 provides that NERC may require that the Regional Entity Hearing Body's decision be modified by the Regional Entity "in accordance with, as applicable to the particular decision, Sections 5.8, 5.9 and 6.5 of Appendix 4C." NERC states that this provision ensures "consistency in violation, Penalty and Mitigation Plan determinations for similar facts and circumstances."⁴⁵

Comments

60. The Trade Associations protest that the Commission should direct NERC to revise Section 413 "to limit exercise of this authority solely to address incorrect procedural or legal decisions by the Hearing Body."⁴⁶ The Trade Associations contend that the reference in Section 413 to Section 5.8 of Appendix 4C, which allows NERC to "advise the Compliance Enforcement Authority of any additional detail or further development of the factual findings that NERC deems necessary before the Notice of Penalty is issued," could allow NERC "in its review and processing of a decision by a Hearing Body to go outside of the record and possibly to have *ex parte* communications with the Compliance Enforcement Authority."⁴⁷ The Trade Associations further contend that Section 413 could subject registered entities to "*de novo* review by NERC or NERC could request additional material without additional due process for the Registered Entity ... [and

⁴⁵ NERC Petition at 17.

⁴⁶ Corrected Trade Associations Protest at 8.

⁴⁷ *Id.* at 7.

NERC could] impose penalties directly in such circumstances, without providing further due process to a Registered Entity at the regional level.”⁴⁸

61. MISO agrees that the reviews provided by Section 413 are important for consistency in enforcement actions across Regional Entities. However, MISO contends that such reviews “should not be used to overturn validly-executed and otherwise uncontested settlement agreements.”⁴⁹ MISO states that the Commission should “ensure that NERC’s review in circumstances where a settlement is being considered is performed before any settlement agreement is executed, and incorporates NERC’s concerns into the agreement (rather than leaving those concerns to be addressed after the agreement is executed).”⁵⁰

Commission Determination

62. We approve proposed Section 413 because it will assist NERC in ensuring consistency in violation, penalty and Mitigation Plan determinations for similar facts and circumstances and among Regional Entities. We reject the protests made by the Trade Associations and MISO concerning Section 413.

63. The Trade Associations state that NERC’s review of Regional Entity Hearing Body final decisions under Section 413 could allow NERC to look beyond the record compiled by the Regional Entity Hearing Body and possibly rely on *ex parte* contacts with the Compliance Enforcement Authority. This concern is based on the citation in Section 413 to Section 5.8 of the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure). However, Section 5.8 in Appendix 4C states, “NERC may direct the Compliance Enforcement Authority to revise a Penalty determination, in which case the Registered Entity subject to the Penalty, or the Compliance Enforcement Authority, as applicable, may reopen the proceedings on any issue on which the Penalty was based, irrespective of whether the issue was previously litigated, settled or unopposed.” Accordingly, even if NERC revises a penalty determination based on information not in the record, the registered entity would have the right to reopen the proceedings.

64. With respect to MISO’s concern that NERC reviews of final decisions under Section 413 should not be used to overturn “validly-executed and otherwise uncontested settlement agreements,” Section 5.6 of Appendix 4C, as revised, provides as part of the settlement process that the “Compliance Enforcement Authority shall report the terms of

⁴⁸ *Id.* at 8.

⁴⁹ MISO Protest at 10.

⁵⁰ *Id.*

all settlements of compliance matters to NERC. NERC will review the settlement for the purpose of evaluating its consistency with other settlements entered into for similar violations or under other, similar circumstances.”⁵¹ NERC states that Section 413 was added because “in order for NERC to perform its function of ensuring consistency in violation, Penalty and Mitigation Plan determinations for similar facts and circumstances and among Regional Entities, it is necessary for NERC to review determinations made by Regional Entity Hearing Bodies concerning Alleged Violations, Penalties and Mitigation Plans just as NERC reviews findings of violations, Penalties and Mitigation Plans determined or accepted by Regional Entity Compliance Staffs.”⁵² Because NERC is required to review each settlement agreement pursuant to Section 5.6 “for the purpose of evaluating its consistency with other settlements entered into for similar violations or under other, similar circumstances,” Section 413 would not apply to settlements because to conduct a separate review pursuant to Section 413 would be duplicative of the review already required under Section 5.6.

C. NERC Proposed Revisions to Section 800 (Reliability Assessment and Performance Analysis)

65. NERC proposes to revise Sections 807 and 808 to address, respectively, “Analysis of Major Events” and “Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities.” NERC states that the revisions are intended to provide for a more consistent use of terms (e.g., “major event” and “occurrences”).

Comments

66. MISO states that NERC proposes revisions to Section 808 to expand NERC’s authority to conduct analyses of “off-normal occurrences,” which are described only as occurrences that do not rise to the level of a major event. MISO protests that, while it does not disagree with allowing NERC to perform necessary analyses of non-major events, the definition of “off-normal occurrences” is too vague and should be clarified to specify the types of events that would be subject to NERC analysis.

Commission Determination

67. We approve the proposed revision to Section 807 and also direct NERC to submit information in a compliance filing, as discussed below. NERC proposes to revise Section

⁵¹ Section 5.6 also applies to settlements reached in proceedings where a hearing is requested. See Section 1.8 of Appendix 4C, Attachment 2 (Hearing Procedures).

⁵² NERC Petition at 17-18.

807.5 to provide that it will “establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.” We note that, in February 2012, NERC informed stakeholders that it planned to develop an ERO Event Analysis Process that would address, *inter alia*, the sharing of lessons learned from event analyses.⁵³ The Commission directs NERC to clarify in a compliance filing due within 60 days of the date of this order whether proposed Section 807.5 procedures and protocols for sharing of information are intended to implement or formalize the ERO Event Analysis Process, or otherwise explain the relationship, if any, between revised Section 807.5 and the Event Analysis Process.

68. We approve the proposed revision to Section 808. NERC states that, as revised, the phrase “major events” includes events “such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System.”⁵⁴ NERC explains that it will analyze occurrences that do not rise to the level of a major event, “to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences....”⁵⁵ We believe that NERC needs flexibility to decide which type of analysis is appropriate for a particular occurrence, and which “off-normal” events it chooses to study. We are not persuaded by MISO’s comments that a more precise definition of “major event” is necessary, and believe that it would reduce NERC’s flexibility in determining the appropriate level of analysis – and thus resources – to apply when studying a system occurrence.

D. NERC Proposed Revisions to Appendix 4B (Sanction Guidelines),

69. In Section 3.3.1 (formerly Section 4.3.1) of NERC’s Sanctions Guidelines, NERC proposes revisions stating that, in evaluating a violator’s compliance history, NERC or the Regional Entity will take into account previous violations by affiliates of the violator, particularly with respect to violations of the same or a similar Reliability Standard Requirement, and will evaluate whether any such prior violations reflect recurring

⁵³ Electric Reliability Organization Event Analysis Process (February 2012), *available at* http://www.nerc.com/files/ERO_Event_Analysis_Process_Document_Version_1_Feb_2012.pdf.

⁵⁴ NERC Petition at 22 (quoting revised Section 807).

⁵⁵ Revised Section 808.

conduct by affiliates that are operated by the same corporate entity or whose compliance activities are conducted by the same corporate entity. NERC states that the proposed revision is consistent with prior Commission guidance and should promote the sharing of compliance information and lessons learned among registered entities that are corporate affiliates.⁵⁶

Comments

70. OEVC protests this revision because it states that taking previous violations by affiliates into account when evaluating a registered entity's compliance history violates section 215 of the FPA. OEVC contends that taking into account the compliance history of affiliated entities in the penalty determination process violates the principles that "[a]ll enforcement activities under Section 215 of the FPA must be directly tied to enforcing compliance with reliability standards, and all penalties must bear a 'reasonable relation to the seriousness of the violation.'"⁵⁷ OEVC maintains that the actions of an affiliate do not influence whether a penalty is reasonable in relation to the seriousness of an entity's own violation and, because affiliates often do not remain static, an entity's current affiliates may not have been affiliates at the time of the alleged violation. OEVC also contests NERC's assertion that the proposed revision is consistent with the Commission's past guidance.

Commission Determination

71. We approve the proposed revision to Section 3.3.1 of Appendix 4B. We reject the argument raised by OEVC that the consideration of affiliates in this context is contrary to section 215. The proposed revision requires NERC to consider previous violations by affiliates of the violator to determine whether "any such prior violations reflect recurring conduct by affiliates that are operated by the same corporate entity or whose compliance activities are conducted by the same corporate entity." Consistent with previous Commission guidance, it is reasonable to consider past violations of an affiliate operated by, or whose compliance activities are conducted by, the same parent as the entity subject to penalty because repeat violations may be the result of actions by the controlling parent entity.⁵⁸ Moreover, as noted in NERC's petition, Repetitive Violations and Compliance History is only one of nine proposed Adjustment Factors used in determining penalties.

⁵⁶ NERC Petition at 32-33 (citing *North American Electric Reliability Corp.*, 132 FERC ¶ 61,182, at P 7 (2010)).

⁵⁷ OEVC Protest at 3 (citing 16 U.S.C. § 824o(e)(6)).

⁵⁸ *North American Electric Reliability Corp.*, 132 FERC ¶ 61,182, at P 7 (2010) ("Notices of Penalty should explain how NERC and Regional Entities assessed whether

E. NERC Proposed Revisions to Appendix 4C (Compliance Monitoring and Enforcement Program)

72. NERC proposes revisions to Appendix 4C, the Compliance Monitoring and Enforcement Program (CMEP). We address below NERC's proposed revisions to Sections 1.1, 3.0, 3.1.5.4, 3.3.1, 3.4.1, 3.5, 4.1, 4.2, 5.0, 5.3, 5.11, 8.2, CMEP Attachment 1, and CMEP Attachment 2.⁵⁹

1. Section 1.1

73. In Section 1.1, NERC proposes to modify the definition of "Confirmed Violation" to read:

Confirmed Violation: An Alleged Violation for which (1) ~~an the Registered eEntity has:~~ (1) accepted or not contested the Notice of Alleged Violation and Proposed Penalty or Sanction or other notification of the Alleged Violation ~~finding of the violation by a Regional Entity or NERC and will not seek an appeal,~~ or (2) there has been the issuance of a final order from NERC or a Regional Entity Hearing Body finding a violation, Penalty or sanction completed the hearing and appeals process within NERC, or (3) ~~allowed the period time for requesting a hearing or submitting an appeal has to expired,~~ or (4) the Registered Entity has executed a settlement agreement pursuant to Section 5.6 ~~admitted to the violation in a settlement agreement.~~

74. NERC states that the definition has been "expanded to more comprehensively capture the circumstances that, based on experience, constitute a Confirmed Violation."⁶⁰ NERC further states that it "intends the term Confirmed Violation to encompass the end-state of the enforcement process for an Alleged Violation, whether that end state is reached by the Registered Entity accepting or not contesting the Alleged Violation, an actual determination by a Regional Entity Hearing Body or NERC that a violation

instant violations may reflect recurring conduct by the same registered entity or by an affiliate or department that is operated by the same corporate entity ...").

⁵⁹ The revision to CMEP Attachment 2 is related to new Section 414 of the Rules of Procedure, which is also addressed below.

⁶⁰ NERC Petition at 35.

occurred, the expiration of the time allowed for requesting a hearing or filing an appeal, or execution of a settlement agreement that resolves the Alleged Violation.”⁶¹

Comments

75. MISO and OEVC protest that NERC’s revised definition of Confirmed Violation could include a settlement in which a registered entity neither admits nor denies a violation. MISO and OEVC question whether the expansion of the definition of Confirmed Violation to include settlements where there has been no specific admission of a violation would cause such settlements to be viewed as negative precedent during future enforcement actions. Moreover, MISO contends that, if that interpretation occurs, registered entities will have less incentive to settle alleged violations and could be more willing to litigate such alleged violations. MISO states that the Commission should clarify that the expansion of the definition of Confirmed Violation to include settlements where the registered entity has neither admitted nor denied a violation will not cause settlements to be deemed to be negative precedent during future enforcement actions.

Commission Determination

76. We approve the proposed modification to the definition of Confirmed Violation. With respect to the protesters’ concerns, we believe that NERC adequately addressed this issue in its petition:

Further, with respect to any concern that a Confirmed Violation is a determination of ‘guilt,’ and the potential impact of the existence of a Confirmed Violation for the Registered Entity on the enforcement process and potential Penalties for future Possible Violations or Alleged Violation, the settlement agreement and the Notice of Penalty for the Confirmed Violation will reflect that the Confirmed Violation was arrived at through a settlement agreement in which the Registered Entity neither admitted or denied the Alleged Violation.⁶²

77. Based on NERC’s statement, we do not believe that the expansion of the definition of Confirmed Violation to include settlements where the registered entity has neither admitted nor denied a violation will discourage the settlement process. In addition, NERC’s revision does not change the current practice whereby settlements are part of an entity’s compliance history.⁶³ Whether settlements are treated as “negative precedent” in

⁶¹ *Id.*

⁶² NERC Petition at 35-36.

⁶³ *North American Electric Reliability Corp.*, 132 FERC ¶ 61,182, at P 4 n.10

future enforcement proceedings, either as they are now or under the proposed revision, is based on a case-by-case analysis.

2. Section 3.0 and CMEP Attachment 1

78. NERC proposes to revise Section 3.0, which addresses “Compliance Monitoring Processes,” in relevant part to state:

~~The Compliance monitoring processes in this Section Program~~ requires timely information, reports and data from Registered Entities to effectively monitor compliance with Reliability Standards. The Compliance Enforcement Authority has authority to collect Documents, data and information in the manner it deems most appropriate, including requesting copies of Documents, data and information to be made and removing those copies from the Registered Entity’s location in accordance with appropriate security procedures conforming to Section 1500 of the Rules of Procedure. ... If Documents, data, information or other reports to determine compliance requested from a Registered Entity are not received by the Required Date, the Compliance Enforcement Authority may execute the steps described in Attachment 1, Process for Non-submittal of Requested Data.

79. NERC proposes revisions to CMEP Attachment 1, Process for Non-submittal of Requested Data, providing a three-step process to be followed when an entity does not provide requested data. Step 1 provides that the Compliance Enforcement Authority will issue a notice to the registered entity stating that the required date for reporting has passed. Step 2 provides that, if the entity remains non-responsive, and if data is not received within 10 business days, “the Compliance Enforcement Authority may (i) implement a compliance monitoring process directed to the Registered Entity, or (ii) issue a Notice or other notifications of Alleged Violation and Proposed Penalty or Sanction at the Severe Violation Severity Level to the Registered Entity for the Reliability Standard Requirement to which the requested or required data, information or report relates.” Step 3 provides that, if the registered entity fails to produce the requested data within ten days of the notice issued in step 2, the Compliance Enforcement Authority may take any action of which the registered entity was notified in the step 2 notice. Further, Attachment 1 includes a statement that this process is not intended to apply where a registered entity timely requests additional time to respond and works with the Compliance Enforcement Authority in good faith to respond to the request.

(2010) (treating settlement of prior violation as part of entity’s compliance history).

Comments

80. OEVC protests that certain elements of the data collection provision should be deleted or revised because they exceed the scope of section 215 of the FPA with respect to the imposition of penalties and sanctions. OEVC states that step 2 of the process set forth in Attachment 1 provides that NERC can “implement a compliance monitoring process directed to the Registered Entity” while step 3 provides that, if the registered entity does not produce the requested or required information, NERC “may take any action ... including issuing a Notice or other notification of Alleged Violation and Proposed Penalty or Sanction at the Severe Violation Severity Level for the Reliability Standard Requirement to which the requested or required data, information or report relates.” OEVC contends that steps 2 and 3 are unlawful because they could be used to penalize a registered entity for action or inaction unrelated to a violation of a Reliability Standard approved by the Commission.⁶⁴

81. MISO is concerned that the possible penalties and procedures set forth in Attachment 1, Process for Non-submittal of Requested Data, do not adequately account for legitimate objections or difficulties that a registered entity might have in responding to a data request. MISO contends that the potential penalty goes beyond what is necessary to compel production and is, instead, punitive. MISO requests that the Commission remand these provisions to NERC to revise them to account for legitimate objections on the part of a registered entity and to more narrowly tailor the sanctions to those that are necessary to encourage compliance with a data request.

Commission Determination

82. We approve the proposed revisions to Section 3.0 and CMEP Attachment 1.⁶⁵ We reject OEVC’s assertion that the potential steps for failure to supply the required information under CMEP Attachment 1 are unlawful. We find that this provision provides reasonable, measured and lawful responses to entities that are non-responsive to requests for data. The Compliance Enforcement Authority has discretion on how to direct its resources, and a decision to direct those resources to more closely monitor an entity that has failed to respond to a request for data is certainly within the Compliance Enforcement Authority’s prerogative. Likewise, in the context of a substantive violation of the requirements of a Reliability Standard, imposing a more severe Violation Severity Level to recognize the alleged violator’s failure to respond to a data request is a

⁶⁴ The Sanction Guidelines at Section 3.3.d (as revised) require consideration in assessing a penalty of a registered entity’s cooperation.

⁶⁵ The Commission approves, for the same reasons, the similar changes to Section 6.0, Mitigation of Violations of Reliability Standards, proposed in Appendix 4C.

legitimate consideration in determining the appropriate proposed penalty.⁶⁶ We reject OEVC's contention that it is unlawful to consider an entity's action or inaction unrelated to the substance of a violation when determining an appropriate penalty amount. Such rationale would negate consideration of an entity's cooperation during the course of an investigation as a factor in determining a penalty amount.

83. With respect to MISO's concern that the proposed revisions do not adequately account for legitimate objections or difficulties that a registered entity might have in responding to the data request, we find that CMEP Attachment 1 adequately addresses that concern as it expressly provides that the three-step process is not intended to apply where the registered entity requests, prior to the required date for response, clarification, definition of scope, or similar questions concerning the request or seeks additional time to respond and works with the Compliance Enforcement Authority in good faith to respond.

3. Sections 3.1.5.4, 3.3.1 and 3.4.1

84. NERC proposes to revise Section 3.1.5.4, which addresses "Registered Entity Objections to Compliance Audit Team," to read in relevant part:

The Compliance Enforcement Authority will make a final determination on whether the member will participate in the Compliance Audit of the Registered Entity. Nothing in Section 3.1 shall be read to limit the participation generally of NERC staff in the Compliance Audit or to limit the participation generally of FERC staff in a Compliance Audit of a Registered Entity, or involving a portion of the Bulk Power System, over which FERC has jurisdiction (as opposed to participation by individual NERC Staff or FERC staff members to whom the Registered Entity states a valid objection in accordance with Section 3.1.5.4).

85. NERC proposes similar revisions to Sections 3.3.1 and 3.4.1, which address, respectively, "Spot Check Process Steps" and "Compliance Investigation Process Steps." NERC states that registered entities should be able to object to the participation of a particular individual NERC or Commission staff member on an audit team on grounds such as a conflict of interest. NERC asserts that prior Commission orders, while prohibiting registered entities from objecting to NERC or Commission participation generally, were not intended to deny a registered entity the right to object to participation

⁶⁶ The current version of CMEP Attachment 1 allows application of the "Severe" Violation Severity Level for failure to comply with a data request. CMEP Attachment 1 at Step 4 ("Thirty (30) days after the Required Date, a Reliability Standard violation may be applied at the severe Violation Severity Level.").

in a Compliance Audit by an individual NERC staff member or Commission staff member on the same types of grounds that a registered entity can object to participation by a Regional Entity staff member, contractor or industry subject matter expert as a member of the Compliance Audit team.

Commission Determination

86. We reject the proposed revisions to Sections 3.1.5.4, 3.3.1 and 3.4.1 because they assume that the Commission and NERC cannot or will not adequately screen staff members for potential conflicts of interest or bias before selecting members of an audit team. If a registered entity has an objection to the participation in an audit by a particular NERC or Commission staff member, the registered entity should address those concerns to NERC or Commission staff, respectively. This direct consideration is particularly true of participation in CMEP activities by Commission staff members, who are held to legally-enforceable ethical standards established by the Federal Government and the Commission.⁶⁷ The proposed revisions, by contrast, place Regional Entities or NERC in the position of deciding whether a NERC or Commission staff member can serve on an audit team, thus inverting the order of authorities established in section 215.

87. NERC is hereby directed to submit a compliance filing within 60 days of the date of this order that removes these revisions from its proposed Rules of Procedure.

4. Section 3.5

88. NERC proposes to revise Section 3.5, which addresses “Self-Reports,” to state:

Self-Reporting ~~is~~ are encouraged at the time a Registered Entity becomes aware (i) that it has, or may have, of a violation of a Reliability Standard, or (ii) ~~a change in~~ the Violation Severity Level of a previously reported violation has changed. Self-Reporting of a violation of a Reliability Standard are is encouraged regardless of whether the Reliability Standard requires reporting on a pre-defined schedule in the Compliance Program ~~and~~ or whether the violation is determined outside the pre-defined reporting schedule. If possible, and without delaying the Self-Report, a Self-Report may include the actions that have been taken or will be taken to resolve the violation.

89. NERC states that these revisions are consistent with the change to the definition of Self-Report.

⁶⁷ See 18 C.F.R. Part 3C (2012).

Comments

90. MISO seeks clarification on when an entity will receive credit for self-reporting a violation or a potential violation under NERC's proposed Section 3.5. MISO states that NERC's proposed revisions to Section 3.5 encourage entities to submit Self-Reports not only when such an entity is aware that it violated a Reliability Standard, but also when it becomes aware that it "may have" violated a Reliability Standard. MISO requests that the Commission clarify that a regulated entity that waits to self-report under Section 3.5 until after it has conducted its own internal inquiry, and has made a determination regarding its compliance with one or more Reliability Standards, will receive full credit for self-reporting, as long as there was not an unreasonable delay between the discovery of the issue and the time the self-report is submitted. MISO states that such a clarification is consistent with self-reporting as set forth in the Commission's Penalty Guidelines.⁶⁸

Commission Determination

91. We approve NERC's proposed revisions to Section 3.5. NERC's proposed revisions are consistent with the Commission's prior efforts to encourage self-reporting by registered entities and its guidance on appropriate aspects of the self-reporting process.⁶⁹ MISO's concern over when an entity is eligible to receive credit for a self-report is addressed in Section 3.3.3 of NERC's Sanction Guidelines, which states that "NERC or the Regional Entity shall consider whether a violator reported the violation by a Self-Report, prior to detection or intervention by NERC or the Regional Entity."

5. Sections 4.1 and 4.2

92. NERC proposes to revise Section 4.1, which addresses "NERC Compliance Monitoring and Enforcement Program Implementation Plan," to add language stating that "NERC may update and revise the NERC Implementation Plan during the course of the year as necessary. Regional Entities have discretion to make modifications to the NERC Implementation Plan with respect to individual Registered Entities." NERC proposes to revise Section 4.2, which addresses "Regional Implementation Plan," to include similar language for Regional Entities. Other than identifying the changes in the petition, NERC does not address the changes.

⁶⁸ (Citing *Enforcement of Statutes, Orders, Rules, and Regulations*, 132 FERC ¶ 61,216 (2010)).

⁶⁹ See, e.g., *North American Electric Reliability Corp.*, 139 FERC ¶ 61,248, at PP 26-38 (2012) (providing clarifications on the nature of self-reporting and the value of various types of self-reports of possible violations by registered entities).

Commission Determination

93. The Commission approves NERC's proposed revisions to Sections 4.1 and 4.2. The Commission notes that Sections 4.1 and 4.2 currently state that the Implementation Plans for NERC and the Regional Entities will be posted on their respective websites, and those provisions are retained in the revised versions of Sections 4.1 and 4.2. The Commission expects that updates and revisions to the NERC and Regional Entities Implementation Plans, now permitted under the revised language, will be posted on their respective websites in accordance with this existing requirement.

6. Section 5.0 and Sanction Guidelines Section 2.2

94. NERC proposes to insert in CMEP section 5.0 a provision stating that the CMEP enforcement process "may not be the most appropriate, efficient or desirable means by which to achieve the overall objectives of the Compliance Program for NERC, the Compliance Enforcement Authority and the Registered Entity. In such circumstances, other approaches may be considered and applied." NERC observes that the current Sanction Guidelines includes a similar statement, but proposes to delete it, "as the statement relates to compliance enforcement processes and therefore is more appropriately placed in [the CMEP]." ⁷⁰

Commission Determination

95. We approve NERC's proposed revisions to Section 5.0 and Sanction Guidelines Section 2.2. Although NERC does not define or describe "other procedures," we understand that they would be used under limited circumstances and that a registered entity has a choice as to whether to be subject to them. ⁷¹ We also clarify that the "other procedures" should be limited to a reasonable exercise of NERC's enforcement discretion. We expect that any broader changes that NERC is contemplating to its CMEP process will be addressed in a separate proceeding before the Commission. ⁷²

⁷⁰ NERC Petition at 54. The currently effective provision of the Sanction Guidelines Section 3.2 provides, "[A]bsolute adherence to the Compliance Monitoring and Enforcement Programs, to the exclusion of other options, may not be the most appropriate, efficient or desirable means by which to achieve the end goal in all circumstances, to all entities party to a violation."

⁷¹ NERC Petition at 54.

⁷² See, e.g., Agenda Compliance Committee (November 6, 2012), pages 10-11 of PDF document, *available at* http://www.nerc.com/docs/bot/botcc/BOTCC_Open_11-12a-complete.pdf (addressing NERC's Compliance Enforcement Initiative).

7. Section 5.3

96. NERC proposes to revise Section 5.3, which addresses “Notification to Registered Entity of Alleged Violation,” to change the language requiring that “NERC shall forward a copy of the Notice of Alleged Violation to FERC” to now read that “NERC shall notify FERC of the Alleged Violation.” In the petition, NERC does not explain the basis for this change.

Commission Determination

97. Under the proposed revision, NERC would no longer be obligated to forward a copy of the Notice of the Alleged Violation to the Commission and, instead, would only be required to “notify” the Commission. We note that NERC also proposes to specify in Section 5.3 the categories of information that a Compliance Enforcement Authority would provide to a registered entity in a “notification” of Alleged Violation. The Commission accepts NERC’s proposed revisions to Section 5.3 with the understanding that NERC will provide to the Commission the same information the registered entity receives in a “notification” of Alleged Violation.

8. Section 5.11

98. NERC proposes to add new Section 5.11, Special Procedures for an Enforcement Action Against an ISO/RTO Where the Monetary Penalty May be Allocated by the ISO/RTO to Other Entities. NERC states that Section 5.11 allows an ISO/RTO to request that the Compliance Enforcement Authority make a determination during the enforcement process for a Notice of Possible Violation issued to the ISO/RTO that one or more other entities were responsible in whole or in part for actions or omissions that caused or contributed to the violation and that the specified other entity or entities can request and be allowed to participate in the enforcement process. NERC further states that Section 5.11.4 expressly disclaims that the Compliance Enforcement Authority will determine whether and to what extent a penalty imposed on the ISO/RTO should be allocated to other entities. NERC states that such an allocation determination would be made by the Commission in a separate proceeding pursuant to section 205 of the FPA.

Comments and Answers

99. OEVC protests that proposed Section 5.11 grants preferential treatment to ISO/RTOs, and is therefore discriminatory, in that it allows only ISO/RTOs to have NERC determine that “one or more specified other entities were responsible, in whole or in part, for actions or omissions that cause or contributed to the violation.” OEVC states that NERC has not provided a legal basis to grant special treatment to ISO/RTOs and, thus, Section 5.11 violates section 215 of the FPA.

100. ISO/RTO Council responds that OEVC ignores Commission precedent addressing the allocation of reliability penalty costs that are initially assessed against ISO/RTOs to

entities that actually caused a Reliability Standard violation. ISO/RTO Council states that Commission precedent recognizes that ISO/RTOs are differently situated from other registered entities because they “may have insufficient reserves to pay penalties assessed pursuant to section 215 of the [Federal Power Act].”⁷³ ISO/RTO Council states that the Commission established rules that allow ISO/RTOs to seek Commission permission to directly allocate reliability penalties if certain conditions are met. ISO/RTO Council explains that one of the conditions is a due process requirement that entities potentially subject to a penalty allocation receive notice and an opportunity to fully participate in the Compliance Monitoring and Enforcement Program conducted by NERC or the Regional Entities. ISO/RTO Council maintains that Section 5.11 is not unduly discriminatory or preferential to ISO/RTOs and merely conforms NERC’s Rules of Procedure to Commission precedent. ISO/RTO Council further states that OEVC’s assertion that non-ISO/RTO entities would benefit from Section 5.11 is irrelevant because non-ISO/RTOs do not have the characteristics that led the Commission to permit ISO/RTOs to make direct allocations of penalty costs to other entities.

101. OEVC replies that the proposed Special Procedures in Section 5.11 are impermissible under section 215 of the FPA because they would afford special treatment to ISO/RTOs. OEVC states that Commission precedent addressing the allocation of reliability penalty costs under section 205 of the FPA does not support affording preferential treatment to ISO/RTOs through the proposed Special Procedures under section 215 of the FPA. OEVC states that, even if they were relevant, the Special Procedures are not required for ISOs/RTOs to provide notice to targeted entities. OEVC contends that proposed Section 1.2.12 of Attachment 2 to Appendix 4C of the Rules of Procedure specifically addresses the ability of an entity to fully participate in a proceeding in which it may be contractually liable to an ISO/RTO for reliability penalty costs. Thus, OEVC concludes that the proposed Special Procedures are not required for ISOs or RTOs to satisfy the due process requirement that entities potentially subject to a penalty allocation receive “notice and an opportunity to fully participate in the Compliance Monitoring and Enforcement Program conducted by NERC or NERC’s Regional Entities.”⁷⁴

Commission Determination

102. We approve NERC’s proposed new Section 5.11. Proposed new Section 5.11 is consistent with Commission precedent on this subject:

⁷³ ISO/RTO Council at 7 (quoting *Reliability Standard Compliance and Enforcement in Regions with Regional Transmission Organizations or Independent System Operators*, 122 FERC ¶ 61,247, at P 1 (2008) (Guidance Order)).

⁷⁴ OEVC Reply at 3-4.

In the event an RTO or ISO itself is assessed a monetary penalty, the Commission will entertain a section 205 filing by that RTO or ISO to directly assign the costs of the penalty to another entity. However, to ensure due process to that targeted entity, the Commission will not entertain any such filing unless the targeted entity has been notified during the course of the investigation or other inquiry into, or hearing of that matter, that an RTO or ISO believes that the targeted entity may be responsible for a violation. It is thus imperative for an RTO or ISO that believes another entity is responsible for a violation to so notify the Regional Entity as soon as possible. Furthermore, to avoid duplicative investigations and hearings, the Commission repeats that it does not intend any section 205 direct assignment proceeding to function as a second, de novo review of the investigation. Rather, such a section 205 proceeding will be limited to the question of whether penalty costs should be assigned to an entity already identified during the investigative or hearing stage of the enforcement process.⁷⁵

103. We reject OEVC's assertion that this precedent does not support proposed Section 5.11. OEVC claims that this precedent is irrelevant to the Rules of Procedure as they pertain to section 215 because it deals exclusively with the allocation of reliability penalty costs under section 205. The last sentence from the passage above, however, states that "a section 205 proceeding will be limited to the question of whether penalty costs should be assigned to an entity *already identified during the investigative or hearing stage of the enforcement process.*" The "investigative or hearing stage of the enforcement process" refers to a section 215 process. In that process, the Commission stated that the Compliance Enforcement Authority, if appropriate, may assign responsibility to the non-ISO/RTO entity.⁷⁶ Proposed Section 5.11, which permits ISO/RTOs to identify other parties potentially responsible in whole or in part for a violation during an enforcement action and to request that a Compliance Enforcement Authority make a determination as to their responsibility, is consistent with this precedent and provides due process to non-ISO/RTO entities.

⁷⁵ Guidance Order, 122 FERC ¶ 61,247 at P 23.

⁷⁶ *Id.* P 23, n.38 ("The Regional Entity ... may then consider the acts or omissions of such entity in the investigative or hearing process, and may assign responsibility to the entity if appropriate").

104. We reject OEVC's assertion that proposed Section 5.11 is unduly discriminatory or preferential because it treats ISO/RTOs differently from other registered entities that have contractual arrangements whereby they can allocate some or all of a monetary penalty to another entity. As the Commission previously determined, we recognize the importance of ISOs and RTOs in providing transmission service, enhancing reliability and administering electric energy markets throughout the country, and acknowledge that these entities, to the extent they operate as not-for-profit organizations funded by their customers, may have insufficient reserves to pay penalties assessed pursuant to section 215 of the FPA.⁷⁷ On that basis, we find that the treatment of ISO/RTOs in proposed Section 5.11 is not unduly discriminatory or preferential.

9. Section 8.2

105. NERC proposes to revise Section 8.2, "Reporting to Applicable Governmental Authorities and Public Disclosure," to read:

~~Regional Entities shall report a Confirmed Violation to NERC at the same time the Notice of Confirmed Violation is issued to the Registered Entity.~~ NERC will publicly post on its website each Notice of Penalty, with any Critical Energy Infrastructure Information or other Confidential Information redacted (unless posting of the Critical Energy Infrastructure Information or Confidential Information has been determined to be permissible in accordance with Section 1500 of the Rules of Procedure) ~~with the identify of the violator~~, together with any statement submitted by the Registered Entity, when NERC files the Notice of Penalty with FERC pursuant to Section 5.9.

NERC does not explain in its petition the reason for removing the requirement that the identity of the violator be included in the public posting.

Commission Determination

106. We reject the proposed revision to Section 8.2 removing the requirement that NERC identify violators in the public posting of the Notice of Penalty, subject to the restrictions imposed by 18 C.F.R. § 39.7(b)(4). NERC does not provide any justification for removing this requirement. The Commission finds that, particularly since NERC's website offers the most accessible point to view Notices of Penalty, removing this requirement would reduce transparency.

⁷⁷ *Id.* P 1.

107. NERC is hereby directed to submit a compliance filing within 60 days of the date of this order that restores the deleted language to Section 8.2.

10. CMEP Attachment 2 and Section 414 of Rules of Procedure

108. NERC proposes to revise Section 1.2.12, Interventions, of CMEP Attachment 2, Hearing Procedures, to allow intervention in Regional Entity Hearing Body proceedings under limited circumstances. NERC states that, while it recognizes that the Commission previously concluded that only the Commission can authorize intervention in NERC or Regional Entity hearings concerning compliance and imposition of Penalties, the proposed revisions will improve the administration of hearings under the Hearing Procedures, and potentially avoid delays and interruptions to the proceedings, if the Regional Entity Hearing Body is authorized to consider requests for intervention and to allow intervention in the limited, defined circumstance set forth in proposed Section 1.2.12(b). Proposed Section 1.2.12(b) states that:

The Hearing Body may allow a Person to intervene only if the Hearing Body determines that the Person seeking intervention has a direct and substantial interest in the outcome of the Alleged Violation, proposed Penalty or sanction, Mitigation Plan, or Remedial Action Directive that is the subject of the proceeding.

Proposed Section 1.2.12(b) provides the following two examples of direct and substantial interest in the outcome:

(1) that the Person seeking intervention has received a Notice of Alleged Violation or a Remedial Action Directive involving the same Reliability Standard requirement(s) and arising out of the same event or occurrence as the existing Respondent(s) that is the subject of the proceeding, or

(2) that the Person seeking intervention will or may be contractually or legally liable to the original Respondent(s) for payment of all or a portion of the proposed Penalty or sanction that is the subject of the proceeding,...

109. Proposed new Section 414 of the Rules of Procedure establishes appellate procedures for grants or denials of motions for intervention made under revised Section 1.2.12. Any appeal is first made to NERC and then to the Commission.

Commission Determination

110. We approve the proposed revisions to Section 1.2.12 allowing Regional Entity Hearing Bodies to permit third parties to intervene. Until now, only the Commission could authorize interventions.⁷⁸ We determine that the standard for intervention proposed by NERC (i.e., “direct and substantial interest in the outcome of the Alleged Violation, proposed Penalty or sanction, Mitigation Plan, or Remedial Action Directive that is the subject of the proceeding) is just, reasonable, not unduly discriminatory or preferential, and in the public interest, and satisfies the requirements of section 215(c). What is more, NERC’s examples of what is a “direct and substantial interest” are consistent with Commission precedent.⁷⁹ We agree with NERC that, as revised, Section 1.2.12 “will improve the administration of hearings under the Hearing Procedures, and potentially avoid delays and interruptions to the proceedings while a potential intervenor prosecutes a request for intervention at the Commission.”⁸⁰ As proposed in revised Section 1.2.12, the Hearing Body’s decision granting or denying intervention can be appealed pursuant to new Section 414 of the Rules of Procedure to NERC and then to the Commission.

F. Rules of Procedure Revision Process

111. The Trade Associations and OEVC raise concerns regarding the process by which NERC revises its Rules of Procedure. The Trade Associations state that they asked NERC to implement specific changes in this process “to ensure greater transparency and notice to stakeholders for any future revisions to the [Rules of Procedure].”⁸¹ The Trade

⁷⁸ *North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, at P 150, *order on reh’g*, 120 FERC ¶ 61,260 (2007) (citing *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)); NERC Petition at 71 (citing *Monongahela Power Co., West Penn Power Co., The Potomac Edison Co., and PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,226 (2011)).

⁷⁹ *North American Electric Reliability Corp.*, 119 FERC ¶ 61,060 at P 150 (stating that an exception to the general rule against third party intervention is when more than one registered entity receives a notice of alleged violation for the same event or transaction); *Monongahela*, 135 FERC ¶ 61,226 at P 16 (authorizing intervention when intervenor was potentially subject to a direct assignment of monetary penalties resulting from the enforcement action).

⁸⁰ NERC Petition at 70.

⁸¹ Corrected Trade Associations Protest at 9.

Associations request that the Commission direct NERC to implement these changes and make a compliance filing. Similarly, OEVC states that the “lack of transparency in the [Rules of Procedure] revision process frustrates stakeholder participation and impedes meaningful progress by precluding consideration of alternative ideas and solutions that stakeholders may have otherwise been able to provide if they understood the ‘basis and purpose’ for proposed revisions.”⁸² OEVC requests that the Commission direct NERC to adopt a more comprehensive and transparent process for modifying the Rules of Procedure to more resemble the Standards Development Process.

112. In response, NERC states that the instant petition does not propose changes to NERC’s processes for revising its Rules of Procedure of the kind requested by the Trade Associations and OEVC. NERC states that it would be premature for the Commission to direct NERC to make changes to its processes, when NERC has not developed any such changes through its internal processes, obtained NERC Board approval for any such changes, or proposed any such changes. NERC states that it is aware of the concerns of the Trade Associations and OEVC and that NERC staff is reviewing the process for Rules of Procedure changes and whether any revisions or enhancements are needed.

Commission Determination

113. NERC has not proposed changes to the process for changing its Rules of Procedure commensurate with the comments. However, in its answer NERC commits to considering this issue. The Commission expects NERC will follow through on that effort and propose any changes if necessary for future proposed Rules of Procedure changes.

The Commission orders:

(A) NERC’s revised Rules of Procedure are hereby conditionally approved, with limited exceptions, as discussed in the body of this order.

(B) NERC is hereby directed to submit a compliance and an informational filing within 60 days from the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

⁸² OEVC Protest at 12.



FACTS

NEWS

STATEMENT

BIOs

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. RM12-6-000 & RM12-7-000

Item No. E-5

December 20, 2012

Commissioner Cheryl A. LaFleur

STATEMENT

Statement of Commissioner Cheryl A. LaFleur on Revised Definition of Bulk Electric System

"Today's final rule approving a new definition of "bulk electric system" (BES) marks a significant moment in the Commission's oversight of electric reliability and in the evolution of our relationship with NERC.

"The BES, of course, is the universe of facilities that must comply with mandatory reliability standards. Therefore, it is critical that it include all facilities necessary for reliable operation of the grid. In Order No. 743, the Commission found that the currently effective definition fails to satisfy this basic requirement because it allows each region to identify for itself which facilities are included in the BES, which in turn has led to inconsistencies across regions and potential gaps in reliability.

"The definition we approve today eliminates the broad regional discretion that concerned the Commission in Order No. 743 and replaces it with a general 100 kV threshold, a thoughtful and nuanced list of specifically included and excluded facilities, and an exception process to add or remove specific facilities. I believe that it addresses the Commission's technical concerns and is a major step forward in ensuring that the BES includes all facilities necessary for reliable operation of the grid.

"The definition we approve today also reflects, and defines, the limits of our jurisdiction. In my remarks on the NOPR, I observed that the Commission had deferred to this proceeding the question of whether the local distribution facilities excluded from its jurisdiction under section 215 are the same local distribution facilities excluded from its jurisdiction under section 201(b). In today's final rule, the Commission finds that they are, and that it will apply the same seven-factor test under both sections of the statute.

"Today's order illustrates the success of the new paradigm for Commission directives established in Order No. 743. There, the Commission explained that directives should not be unduly prescriptive, but should instead identify and explain the Commission's reliability concerns, offer NERC guidance and suggestions as to acceptable solutions, and permit NERC to propose equally efficient and effective alternatives. NERC responded in this proceeding by developing a comprehensive definition that addressed our technical concerns with creativity and care.

"Additionally, NERC and the Standards drafting team deserve praise for their focus and timeliness in developing and submitting the revised definition. As I have noted before, all drafting teams are composed of volunteers and the work they do for NERC is in addition to their day jobs at their companies. I also want to thank the FERC staff that worked on this very detailed and well-written (and even well-illustrated) order. I know that you worked very hard to present us with this draft final rule within six months of the NOPR. I hope that this process, and especially the mutual commitment to timeliness, can be a model for both FERC and NERC going forward.

"Finally, as we close out another year, it is appropriate to consider our approval of the new BES definition in the context of the larger relationship and efforts of the industry, NERC, and the Commission to carry out our responsibilities under section 215. In the past year, we have approved standards relating to cybersecurity and vegetation management, as well as a new compliance protocol in the FFT order, and ordered NERC to develop standards to address geomagnetic disturbances. In addition, NERC and its stakeholders are working on improvements in prioritization of reliability issues, focusing on both the standard development and compliance management processes, which we look forward to hearing more about in the new year. While the road has sometimes been bumpy, I believe



FACTS

NEWS

STATEMENT

BIOGRAPHY

FERC and NERC have accomplished a lot together. As we move forward to advance our shared goal of improving the reliability of the bulk electric system, we should build on the shared commitment and collaboration among FERC, NERC, and industry that we saw in this proceeding.”

Document Content(s)

E-5-LAFLEUR.PDF.....1-2

**December 20, 2012****News Media Contact****Craig Cano | 202-502-8680**

Docket Nos. RM12-6-000, RM12-7-000

FEDERAL ENERGY REGULATORY COMMISSION

NEWS

FERC Approves Revised Definition of Bulk Electric System

The Federal Energy Regulatory Commission (FERC) today issued a final rule revising the definition of the bulk electric system. The revisions, proposed by the North American Electric Reliability Corporation (NERC), should provide greater transparency and uniformity in defining the bulk electric system.

Key revisions to the current definition remove language allowing for broad discretion across the reliability regions and establish a “bright-line” threshold that includes all facilities operated at or above 100 kilovolts.

Today’s final rule also establishes a process for seeking a Commission ruling on whether facilities otherwise included in the bulk power system are used in local distribution as set forth in the Federal Power Act. The starting point for this case-by-case analysis will be Order No. 888’s seven-factor test for determining whether a facility is a local distribution or transmission facility; however, FERC will consider other factors based on the specific situation.

In other revisions, the final rule:

- Identifies five facilities configurations that are included in the bulk electric system.
- Identifies four facilities configurations that are not included in the bulk electric system.
- Accepts North American Electric Reliability Corporation’s proposed exception process rules to add or remove system elements from the definition on a case-by-case basis.

The final rule takes effect 60 days after publication in the *Federal Register*.

R-13-11

(30)



FACTS

NEWS

STATEMENT

BIOs

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. RM12-6-000 & RM12-7-000

Item No. E-5

December 20, 2012

Commissioner John R. Norris

STATEMENT

Statement of Commissioner John R. Norris on Revised Definition of Bulk Electric System

"I consider the process that led to today's Final Rule to be a success story in our ongoing efforts to improve the process of developing and implementing mandatory reliability standards under section 215 of the Federal Power Act.

"While speed is relative, it is worth noting that in about two years, we have moved from Order No. 743, which directed NERC to revise its definition of bulk electric system, to today's Final Rule. In that time, NERC conducted an industry stakeholder process, the Commission issued a NOPR on the results of that process, we analyzed numerous comments on that NOPR, and today we issue a Final Rule on NERC's proposal.

"The end result is a Final Rule that overwhelmingly approves the work of NERC and industry stakeholders in crafting the new bulk electric system definition. This shows that when FERC and NERC work together, clearly define goals and expectations, and avoid surprises, a quality product can result.

"With respect to the substance of today's Final Rule, I note that there are two narrow instances in this order where the Commission reserves to itself a direct role in defining the bulk electric system. Specifically, the draft Final Rule concludes that, where necessary, questions of fact regarding whether a facility is used in local distribution (and thus excluded from the bulk electric system under section 215) should be resolved directly by the Commission, rather than through NERC's exceptions process. In addition, the draft Final Rule finds that the Commission has authority under section 215 to act on its own to designate facilities for inclusion in the bulk electric system if it deems that such action is necessary.

"As I have said many times, I believe the FERC-NERC construct works best when FERC sets the overall policy direction, and leaves the day-to-day implementation of the mandatory reliability standards regime to NERC, the Regional Entities and industry. These two portions of the Final Rule, in some measure, deviate from this framework. However, in both instances we emphasize that direct Commission action should be rare. I support these two aspects of today's Final Rule, but hope that we will monitor them in practice to ensure that they do not interfere or conflict with the overall FERC-NERC working relationship."

Document Content(s)

E-5-NORRIS.PDF.....1-1

141 FERC ¶ 61,236
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket Nos. RM12-6-000 and RM12-7-000; Order No. 773]

Revisions to Electric Reliability Organization Definition of Bulk Electric System and
Rules of Procedure

(Issued December 20, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: In this Final Rule, pursuant to section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) approves modifications to the currently-effective definition of “bulk electric system” developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The Commission finds that the modified definition of “bulk electric system” removes language allowing for regional discretion in the currently-effective bulk electric system definition and establishes a bright-line threshold that includes all facilities operated at or above 100 kV. The modified definition also identifies specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of “bulk electric system.”

In this Final Rule, the Commission also approves: (1) NERC’s revisions to its Rules of Procedure, which create an exception process to add elements to, or remove

elements from, the definition of “bulk electric system” on a case-by-case basis;
(2) NERC’s form entitled “Detailed Information to Support an Exception Request” that entities will use to support requests for exception from the “bulk electric system” definition; and (3) NERC’s implementation plan for the revised “bulk electric system” definition.

EFFECTIVE DATE: This Final Rule will become effective [INSERT DATE 60 days after publication in the **FEDERAL REGISTER**]

FOR FURTHER INFORMATION CONTACT:

Susan Morris (Technical Information)
Office of Electric Reliability, Division of Reliability Standards
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-6803

Nicholas Snyder (Technical Information)
Office of Energy Market Regulation, Division of Electric Power Regulation-Central
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-6408

Robert Stroh (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-8473

SUPPLEMENTARY INFORMATION:

141 FERC ¶ 61,236
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure Docket Nos. RM12-6-000
RM12-7-000

ORDER NO. 773

FINAL RULE

(Issued December 20, 2012)

TABLE OF CONTENTS

I. Background	5.
A. Section 215 of the FPA	5.
B. Order No. 693	6.
C. Order No. 743	8.
D. NERC Petitions	11.
1. Revised Definition of Bulk Electric System	12.
2. NERC Petition for Approval of Revisions to Rules of Procedure to Adopt an Exception Process	26.
E. Commission NOPR	29.
II. Discussion	31.
A. Approval of the Revised Bulk Electric System Definition	32.
NOPR Proposal	32.
Comments	33.
Commission Determination	38.
B. The Core Definition of Bulk Electric System	45.
NOPR Proposal	45.
Comments	46.
C. Local Distribution	57.
Comments	58.
Commission Determination	66.

D. Inclusions and Exclusions in the Definition of Bulk Electric System	<u>74.</u>
1. Inclusion I1 (Transformers).....	<u>75.</u>
Commission Determination	<u>80.</u>
2. Inclusion I2 (Generating Resources)	<u>83.</u>
3. Inclusion I3 (Blackstart Resources).....	<u>97.</u>
4. Inclusion I4 (Dispersed Power Producing Resources)	<u>104.</u>
5. Inclusion I5 (Static or Dynamic Reactive Power Devices).....	<u>116.</u>
Exclusions.....	<u>125.</u>
6. Exclusion E1 (Radial Systems)	<u>127.</u>
7. Exclusion E2 (Behind the Meter Generation)	<u>178.</u>
8. Exclusion E3 (Local Networks)	<u>185.</u>
9. Exclusion E4 (Reactive Power Devices)	<u>235.</u>
E. The NERC Rules of Procedure Exception Process, RM12-7-000	<u>238.</u>
NOPR Proposal.....	<u>238.</u>
1. How Entities Will Review and Seek Inclusion of Necessary Elements	<u>263.</u>
2. NERC Role in Identifying Necessary Elements.....	<u>270.</u>
3. Commission Role in Identifying Necessary Elements	<u>279.</u>
4. Technical Review Panel	<u>289.</u>
NOPR Proposal.....	<u>289.</u>
5. Use of Industry Subject Matter Experts	<u>295.</u>
6. NERC's Detailed Information Form	<u>298.</u>
7. NERC's Implementation Plan	<u>302.</u>
NOPR Proposal	<u>302.</u>
8. NERC List of Facilities Granted Exceptions.....	<u>305.</u>
9. Declassification of Facilities	<u>311.</u>
III. Information Collection Statement	<u>319.</u>
IV. Regulatory Flexibility Act Analysis	<u>333.</u>
V. Environmental Analysis	<u>339.</u>
VI. Document Availability	<u>340.</u>
VII. Effective Date and Congressional Notification	<u>343.</u>

1. Pursuant to section 215(d) of the Federal Power Act (FPA),¹ the Commission approves modifications to the currently-effective definition of “bulk electric system” developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). The Commission finds that the modified definition of “bulk electric system” improves upon the currently-effective definition by establishing a bright-line threshold that includes all facilities operated at or above 100 kV and removing language that allows for broad regional discretion. The modified definition also provides improved clarity by identifying specific categories of facilities and configurations as inclusions and exclusions to the definition of “bulk electric system.”

2. We believe that the proposed “core” definition, together with the more granular inclusions and exclusions, should produce consistency in identifying bulk electric system elements across the reliability regions. In addition, we find that NERC’s proposed case-by-case exception process to add elements to, and remove elements from, the definition of the bulk electric system adds transparency and uniformity to the determination of what constitutes the bulk electric system.

3. We recognize the substantial work invested by NERC and industry participants in developing the modified bulk electric system definition. We also appreciate that NERC timely submitted the revised definition within the twelve month time frame directed by

¹ 16 U.S.C. 824o(d) (2006).

the Commission in the underlying order, Order No. 743, which tasked NERC with this project.² We believe that NERC and industry's efforts provide a technically grounded and legally supportable foundation for identifying elements and facilities that make up the bulk electric system. Other highlights of the Final Rule include:

- accepts NERC's revisions to its Rules of Procedure, which creates an exception procedure to add elements to, or remove elements from, the definition of "bulk electric system" on a case-by-case basis;
- approves NERC's implementation plan for the revised "bulk electric system" definition;
- approves NERC's form entitled "Detailed Information to Support an Exception Request" that entities will use to support requests for exception from the "bulk electric system" definition;
- finds that the Commission can designate sub-100 kV facilities, or other facilities, as part of the bulk electric system, provided that the Commission provides opportunity for notice and comment; and
- establishes a process pursuant to which an entity can seek a determination by the Commission whether facilities are "used in local distribution" as set forth in the Federal Power Act.

² *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 133 FERC ¶ 61,150 (2010), *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011).

4. In the Notice of Proposed Rulemaking (NOPR), the Commission requested comment on certain aspects of NERC's petition to better understand the application of the "core" definition, as well as the specific inclusions and exclusions.³ The explanations provided by NERC and other entities in their comments have assisted in our understanding of the parameters of the definition, and we adopt many of these explanations in the Final Rule. However, in two particular circumstances we believe further action is necessary. We direct NERC to implement the bulk electric system definition consistent with the Commission determinations below. Specifically, we direct NERC to implement the exclusions for radial systems and local networks so that they do not apply to tie-lines for bulk electric system generators. In addition, we direct NERC to modify the local network exclusion to remove the 100 kV minimum operating voltage to allow systems that include one or more looped configurations connected below 100 kV, (as shown in figures 3 and 5 below) to be eligible for the local network exclusion. Further explanation of these configurations and the rationale for our determinations is provided below.

³ *Revision to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Notice of Proposed Rulemaking, 77 FR 39857 (July 5, 2012) 139 FERC ¶ 61,247 (2012) (NOPR).

I. Background**A. Section 215 of the FPA**

5. 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.⁴ The Commission established a process to select and certify an ERO⁵ and, subsequently, certified NERC as the ERO.⁶

B. Order No. 693

6. On March 16, 2007, in Order No. 693, pursuant to section 215(d) of the FPA, the Commission approved 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the NERC Glossary, which includes NERC's definition of bulk electric system.⁷ That definition provides:

⁴ See 16 U.S.C. 824o(e)(3) (2006).

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 *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006) (certifying NERC as the ERO responsible for the development and enforcement of mandatory Reliability Standards), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

⁷ *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.⁸

7. In approving NERC's definition of bulk electric system, the Commission stated that "at least for an initial period, the Commission will rely on the NERC definition of bulk electric system and NERC's registration process to provide as much certainty as possible regarding the applicability to and the responsibility of specific entities to comply with the Reliability Standards."⁹ The Commission also stated that "[it] remains concerned about the need to address the potential for gaps in coverage of facilities."¹⁰

C. Order No. 743

8. On November 18, 2010, the Commission revisited the definition of "bulk electric system" in Order No. 743, which directed NERC, through NERC's Reliability Standards Development Process, to revise its definition of the term "bulk electric system" to ensure that the definition encompasses all facilities necessary for operating an interconnected transmission network.¹¹ The Commission also directed NERC to address the

⁸ Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 75 n.47.

⁹ *Id.* P 75; *see also* Order No. 693-A, 120 FERC ¶ 61,053 at P 19 ("the Commission will continue to rely on NERC's definition of bulk electric system, with the appropriate regional differences, and the registration process until the Commission determines in future proceedings the extent of the Bulk-Power System").

¹⁰ Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 77.

¹¹ Order No. 743, 133 FERC ¶ 61,150 at P 16.

Commission's technical and policy concerns. Among the Commission's concerns were inconsistencies in the application of the definition and a lack of oversight and exclusion of facilities from the bulk electric system required for the operation of the interconnected transmission network. In Order No. 743, the Commission concluded that the best way to address these concerns was to eliminate the Regional Entity discretion to define bulk electric system without NERC or Commission review, maintain a bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and adopt an exemption process and criteria for removing from the bulk electric system facilities that are not necessary for operating the interconnected transmission network. In Order No. 743, the Commission allowed NERC to "propose a different solution that is as effective as, or superior to, the Commission's proposed approach in addressing the Commission's technical and other concerns so as to ensure that all necessary facilities are included within the scope of the definition."¹² The Commission directed NERC to file the revised definition of bulk electric system and its process to exempt facilities from inclusion in the bulk electric system within one year of the effective date of the final rule.¹³

9. In Order No. 743-A, the Commission reaffirmed its determinations in Order No. 743. In addition, the Commission clarified that the issue the Commission directed

¹² *Id.*

¹³ *Id.* P 113.

NERC to rectify was the discretion the Regional Entities have under the current definition to define the bulk electric system in their regions without any oversight from the Commission or NERC.¹⁴ The Commission also clarified that the 100 kV threshold was a “first step or proxy” for determining which facilities should be included in the bulk electric system.¹⁵

10. The Commission further clarified that the statement in Order No. 743, “determining where the line between ‘transmission’ and ‘local distribution’ lies ... should be part of the exemption process the ERO develops” was intended to grant discretion to NERC, as the entity with technical expertise, to develop criteria to determine how to differentiate between local distribution and transmission facilities in an objective, consistent, and transparent manner.¹⁶ The Commission stated that the “Seven Factor Test” adopted in Order No. 888 could be relevant and possibly a logical starting point for determining which facilities are local distribution for reliability purposes.¹⁷ However, the

¹⁴ Order No. 743-A, 134 FERC ¶ 61,210 at P 11.

¹⁵ *Id.* PP 40, 67, 102-103.

¹⁶ *Id.* P 68. 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 at 31,783-84 (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).

¹⁷ Order No. 743-A, 134 FERC ¶ 61,210 at P 69.

Commission left it to NERC to determine if and how the Seven Factor Test should be considered in differentiating between local distribution and transmission facilities for purposes of determining whether a facility should be classified as part of the bulk electric system.¹⁸ Order No. 743-A re-emphasized that local distribution facilities are excluded from the definition of Bulk-Power System and, therefore, must be excluded from the definition of bulk electric system.¹⁹

D. NERC Petitions

11. On January 25, 2012, NERC submitted two petitions pursuant to the directives in Order No. 743: (1) NERC's proposed revision to the definition of "bulk electric system" which includes provisions to include and exclude facilities from the "core" definition; and (2) revisions to NERC's Rules of Procedure to add a procedure creating an exception process to classify or de-classify an element as part of the "bulk electric system."

1. Revised Definition of Bulk Electric System

12. In Docket No. RM12-6-000, NERC filed a petition requesting Commission approval of a revised definition of "bulk electric system" in the NERC Glossary (NERC BES Petition). The definition consists of a "core" definition and a list of facilities configurations that will be included or excluded from the "core" definition. NERC proposed the following "core" definition of bulk electric system:

¹⁸ *Id.* P 70.

¹⁹ *Id.* PP 25, 58.

Unless modified by the [inclusion and exclusion] lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

NERC also requested approval of the proposed “Detailed Information to Support an Exception Request” form as satisfying the requirement in Order No. 743 that NERC develop “technical criteria” to address exception requests. Finally, NERC requested Commission approval of its plan for implementation of the revised definition of “bulk electric system.”

a. Inclusions and Exclusions to the Definition of Bulk Electric System

13. As part of the revised definition, NERC developed inclusions and exclusions to eliminate discretion in application of the revised “bulk electric system” definition. The inclusions address five specific facilities configurations to provide clarity that the facilities described in these configurations are included in the bulk electric system.

Inclusions:

I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3.

I2 - Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above.

I3 - Blackstart Resources identified in the Transmission Operator’s restoration plan.

I4 - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

I5 - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

14. NERC also explained that the facilities described in inclusions I1, I2, I4, and I5 are each operated or connected at or above 100 kV. According to NERC, inclusion I3 encompasses blackstart resources identified in a transmission operator's restoration plan, which are necessary for the operation of the interconnection transmission system and should be included in the bulk electric system regardless of their size (MVA) or the voltage at which they are connected. NERC stated that the inclusions will further reduce the potential for the exercise of discretion and subjectivity to exclude such configurations from the bulk electric system.

15. NERC explained that inclusion I1 includes transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under exclusion E1 or E3. NERC stated that transformers operating at 100 kV or higher are part of the existing definition, but since transformers have windings operating at different voltages, and multiple windings in some circumstances, clarification was required to explicitly identify which transformers are included in the bulk electric system.

16. According to NERC, inclusion I2 includes in the bulk electric system the generator terminals through the high-side of the step-up transformers connected at a

voltage of 100 kV or above. NERC states that this inclusion mirrors the text of the NERC Registry Criteria (Appendix 5B of the NERC Rules of Procedure) for generating units.²⁰

17. As noted above, inclusion I3 includes blackstart resources identified in the transmission operator's restoration plan in the bulk electric system. NERC added inclusion I4 to accommodate the effects of variable generation on the bulk electric system and inclusion I5 to address static or dynamic devices dedicated to supplying or absorbing reactive power that are connected at 100 kV or higher.

18. NERC's modified definition of bulk electric system also provides four exclusions regarding facilities configurations that are not included in the bulk electric system.

Generally, the exclusions address radial systems, behind-the-meter generation and local networks that distribute power to load:

Exclusions:

E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

- a) Only serves Load. Or,
- b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

²⁰ See section III.c.1 and III.c.2 of Appendix 5B of the NERC Rules of Procedure.

- c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

E2 - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA; and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

E3 - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk-power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk-power transfer across the interconnected system. The LN is characterized by all of the following:

- a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);
- b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
- c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

E4 – Reactive Power devices owned and operated by the retail customer solely for its own use.

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

19. NERC explained that exclusion E1 is intended to enhance the clarity of the radial facilities exclusion and that criteria “b” and “c” of exclusion E1 identify the maximum amount of generation allowed on the radial facility while still qualifying for the radial facilities exclusion. NERC added the “normally open switch” note at the end of exclusion E1 to address a common network configuration in which two separate sets of facilities would be recognized as radial systems and not included in the bulk electric system are connected by a “normally open switch” which is a switch is set to the open position for reliability purposes.²¹

20. NERC explained that the normally open switch note avoids numerous exception requests because this configuration is common and subjecting two sets of radial facilities that are normally unconnected to each other because the switch between them is open to the Reliability Standards during the limited time periods when the switch is closed for maintenance-related or outage-related circumstances is impractical and unworkable.

21. According to NERC, exclusion E2 excludes a generating unit or units on the customer’s side of the retail meter that serves all or part of the retail load subject to allowing a limited amount of generating capacity to be connected and that standby, back-up, and maintenance power services are provided to the generating unit. NERC stated

²¹ NOPR, 139 FERC ¶ 61,247 at P 27 (citing NERC BES Petition at 19).

that these generating units are not necessary for the operation of the interconnected transmission network because they serve a single retail load, provide a limited amount of capacity to the bulk electric system, and are fully backed up by other resources.

22. With respect to the “local network” exclusion (exclusion E3), NERC explained that it encompasses local networks of transmission elements operated at between 100 kV and 300 kV that distribute power to load rather than transfer bulk power across the interconnected system. NERC further explained that local networks are not intended to provide transfer capacity for the interconnected transmission network and such networks should not be included in the bulk electric system, and the conditions established in exclusion E3 are sufficient to ensure that such local networks are being used exclusively for local distribution purposes. NERC adds that facilities used for the local distribution of electric energy are expressly excluded from the bulk electric system by the core definition as well as by the local network exclusion.²²

b. Detailed Information to Support an Exception Request

23. In response to the Order No. 743 directive to develop technical criteria to use in addressing requests for exceptions to the definition of the bulk electric system, NERC developed an alternative approach because it would be more feasible to develop a common set of data and information that Regional Entities and NERC could use to

²² See NOPR, 139 FERC ¶ 61,247 at P 30; See also NERC BES Petition at 22-23.

evaluate exception requests rather than to develop the detailed criteria.²³ The Detailed Information Form contains a common set of data that entities seeking an exception must submit with every exception request. According to NERC, the information that an applicant may submit in support of an exception request is not limited to the Detailed Information Form. Rather, an applicant is expected to submit all relevant data, studies and other information that support the exception request, and the Regional Entity and NERC may ask an applicant to provide other data and studies in addition to the Detailed Information Form.

**c. Implementation Plan for Revised Definition of
“Bulk Electric System”**

24. NERC requested that the revised definition become effective on the first day of the second calendar quarter after receiving applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, on the first day of the second calendar quarter after its adoption by the NERC Board of Trustees. NERC stated that the proposed effective date is appropriate to provide a reasonable time between the date of regulatory approval, which is not under the control of NERC or the industry, and the effective date of the revised definition of bulk electric system.

25. NERC also requested that compliance obligations for all newly-identified elements to be included in the bulk electric system should begin twenty-four months after the applicable effective date of the revised definition. While the Commission stated in

²³ NERC BES Petition at 26.

Order Nos. 743 and 743-A that the transition period should not exceed 18 months, NERC explained that it is requesting a longer transition period in light of the actions that entities will need to complete in connection with the revised definition.

2. NERC Petition for Approval of Revisions to Rules of Procedure to Adopt an Exception Process

26. In Docket No. RM12-7-000, NERC filed proposed revisions to its Rules of Procedure for the purpose of adopting an “exception process” mechanism to add elements to, and remove elements from, the bulk electric system. NERC stated that decisions to approve or disapprove exception requests will be made by NERC, rather than by the Regional Entities, thereby eliminating the potential for inconsistency and subjectivity. Further NERC explained that the exception process is “not intended to be used to resolve ambiguous situations,” i.e., the exception process is only available after an initial determination has been made regarding whether an element is part of or not part of the bulk electric system through the application of the definition to the element.”²⁴

27. NERC stated that an owner of an element may submit a request to the applicable Regional Entity to include the element in, or remove it from, the bulk electric system.²⁵ In addition, a Regional Entity, planning authority, reliability coordinator, transmission operator, transmission planner, or balancing authority that has the elements covered by an

²⁴ NOPR, 139 FERC ¶ 61,247 at P 38, *quoting* NERC ROP Petition at 10-11.

²⁵ *See* NOPR, 139 FERC ¶ 61,247 at PP 39-45, detailing the three-step exception process.

exception request within its scope of responsibility may submit an exception request for the inclusion of an element or elements owned by a registered entity. Upon receiving an exception request, the applicable Regional Entity will review the exception request and will issue a recommendation to NERC. NERC will evaluate the Regional Entity recommendation, the accompanying technical documents, the Technical Review Panel opinion (if any), and any comments submitted, and will issue a final determination. Finally, NERC stated that an exception request will be subject to review to verify continuing justification for the exception. NERC also stated that an entity must certify every 36 months to the appropriate Regional Entity that the basis for the exception request remains valid. Further, NERC also included a method for an entity to challenge the NERC decision on an exception request to a NERC Compliance Committee. The entity may also appeal the final NERC decision to the Commission within 30 days following the date of the Compliance Committee's decision, or within such time period as the Commission's legal authority permits.

28. In response to the Order No. 743 Commission statement that NERC should maintain a list of exempted facilities that can be made available to the Commission upon request, NERC maintained that the proposed exception process does not include provisions for such a list, adding that this is an internal administrative matter for NERC to implement that does not need to be embedded in the Rules of Procedure.²⁶ NERC

²⁶ NERC ROP Petition at 49.

stated it will develop a specific internal plan and procedures for maintaining a list of facilities for which exceptions have been granted.

E. Commission NOPR

29. The Commission issued the NOPR on June 22, 2012, and required that comments be filed within 60 days after publication in the *Federal Register*, or September 4, 2012.

While seeking comment on various provisions of NERC's petitions, the NOPR proposed to approve NERC's modification to the currently-effective definition of bulk electric system and changes to the Rules of Procedure to add the exception process. The NOPR also requested comment on the appropriate role for NERC and the Commission in the identification of bulk electric system facilities and elements.

30. The Commission received more than sixty comments on the proposed rulemaking. NERC and other commenters, *inter alia*, respond to the Commissions questions regarding the application of the proposed bulk electric system definition. These comments have assisted us in developing this Final Rule. A list of commenters appears in Appendix A to this Final Rule.²⁷

II. Discussion

31. For the reasons discussed below, the Commission adopts the NOPR proposal and approves NERC's revised definition of bulk electric system and the specific inclusions

²⁷ Further, NERC, MISO, Consumers, MISO Transmission Owners, Barrick, ITC Companies, and AMP filed reply comments. Although the NOPR did not allow for reply comments, we will accept these pleadings because they have assisted our understanding of NERC's proposal in this Final Rule.

and exclusions set forth in the definition, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Likewise, the Commission approves NERC's revised Rules of Procedure that set forth an exceptions process for determining whether elements and facilities are included in the bulk electric system on a case-by-case basis. While we discuss below specific provisions of the NERC proposal, provisions of the modified bulk electric system definition and related Rules of Procedures not specifically mentioned are approved in this Final Rule. Below, we address the following matters: (A) approval of the NERC definition; (B) issues concerning the "core" bulk electric system definition; (C) local distribution; (D) exclusions and inclusions in the bulk electric system definition; and (E) NERC's Rules of Procedures exceptions process.

A. Approval of the Revised Bulk Electric System Definition

NOPR Proposal

32. In the NOPR, the Commission proposed to approve a modification to the currently-effective definition of "bulk electric system" because it removes language allowing for regional discretion in the currently-effective bulk electric system definition, establishes a bright-line threshold that includes all facilities operated at or above 100 kV and identifies specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of bulk electric system.²⁸

²⁸ NOPR, 139 FERC ¶ 61,247 at P 18.

Comments

33. NERC, Regional Entities, trade organizations and a majority of commenters from various industry segments support the Commission's proposal to approve NERC's proposals. APPA "strongly support[s]" NERC's proposed definition.²⁹ EEI supports NERC's proposals and states that any changes to the definition should be made through the standard development process, not through directives. LPPC, NRECA, and WPPC also support approval of the definition and urge the Commission to adopt the NERC proposal and to refrain from pursuing additional regulatory mandates. Snohomish and WPPC agree that NERC has developed a "clear and workable definition" of the bulk electric system that markedly improves the existing definition. They also opine that the definition creates a foundation for reliability that focuses on core elements of the interconnected bulk transmission system, and provides a means for lower-voltage or peripheral elements of the electric system to be excluded from the bulk electric system. Other commenters state that the definition is consistent, repeatable and verifiable and will provide clarity that will assist NERC and affected entities in implementing Reliability Standards.

34. Other commenters, while noting that the NOPR represents a "positive development," believe additional modifications are necessary "to achieve consistency

²⁹ APPA Comments at 7.

within the limitations” of section 215 of the FPA and the Commission’s directives in Order Nos. 743 and 743-A.³⁰

35. Some commenters oppose approval on various grounds. For example, NARUC is concerned that, even though the definition appears to honor the exclusion of local distribution from the bulk electric system, the definition does not go far enough to ensure “that a costly analysis . . . is not required to be performed with regard to local distribution elements that are by law excluded.”³¹ NARUC is also concerned that exclusion E3 (local networks) will exclude some, but not all, local distribution elements. According to NARUC, this could cause confusion as to the status of local distribution elements that are not also described in exclusion E3. Consequently, NARUC believes that the definition does not appropriately reflect the statutory limits of the Commission’s authority under FPA section 215 and its implementation could unnecessarily overreach into state jurisdictional local distribution facilities.

36. NYPSC believes that the proposed definition will likely result in classifying certain facilities as part of the bulk electric system despite their being unnecessary for operating an interconnected transmission network. NYPSC states that the majority of the 138 kV lines within New York City serve as direct feeders to the networked distribution system serving load. NYPSC also states that there is no technical justification for a

³⁰ Holland Comments at 2.

³¹ NARUC Comments at 4.

100 kV bright-line definition.³² NYPSC contends that, even with the exclusions and the exception process, it is uncertain whether an exclusion or exception would apply to the 138 kV lines noted above. NYPSC believes that this approach presumes the Commission has jurisdiction over all facilities operated at 100 kV or above, unless proven otherwise, which inappropriately shifts the legal and technical burdens to the states.

37. NYPSC, NARUC, and the Massachusetts DPU argue that the revised definition does not include a cost impact analysis that weighs costs related to the modified definition against the reliability benefits that the new definition would achieve. They contend that the lack of a cost-benefit analysis accompanying the revised definition represents an additional gap in the process for developing this Reliability Standard. NYPSC and the Massachusetts DPU contend that the costs of compliance with the definition will be excessive. NYPSC states that, according to NERC and the Northeast Power Coordinating Council, Inc. (NPCC), it would exceed \$280 million. Thus, they advocate that, given the significant costs that the revised definition could impose on consumers, the Commission should reject NERC's proposed modifications until they are supported by a cost-benefit analysis.

Commission Determination

38. Pursuant to section 215(d)(2) of the FPA, we approve NERC's revised definition of bulk electric system and the specific inclusions and exclusions set forth in the

³² NYPSC Comments at 3. *See also* Massachusetts DPU Comments at 6-7.

definition, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC's proposal provides additional clarity and granularity that will allow for greater transparency and consistency in the identification of elements and facilities that make up the bulk electric system and is responsive to the technical and policy concerns discussed in Order No. 743.

39. NERC's proposal adequately ensures that all facilities necessary for operating an interconnected electric energy transmission network are included under the bulk electric system. As we observed in Order No. 743,

“[U]niform Reliability Standards, and uniform implementation, should be the goal and the practice, the rule rather than the exception, absent a showing that a regional variation is superior or necessary due to regional differences. Consistency is important as it sets a common bar for transmission planning, operation, and maintenance necessary to achieve reliable operation. . . . [W]e have found several reliability issues with allowing Regional Entities broad discretion without ERO or Commission oversight.”³³

The core definition eliminates the provision that allows broad regional discretion, and establishes a 100 kV bright-line threshold for determining, in the first instance, those elements and facilities that are included in the bulk electric system. The definition also includes specific inclusions and exclusions that address typical system facilities and configurations such as generation and radial systems, providing additional granularity that improves consistency and provides a practical means to determine the status of

³³ Order No. 743, 133 FERC ¶ 61,150 at P 82 (footnote omitted).

common system configurations. Thus, we agree with commenters that the modified definition is consistent, repeatable and verifiable and will provide clarity that will assist NERC and affected entities in implementing Reliability Standards.

40. Accordingly, the Commission finds that NERC's proposal satisfies the directives of Order No. 743 to develop modifications to the currently-effective definition of bulk electric system to ensure that the definition encompasses all facilities necessary for operating an interconnected transmission network and remove the Regional Entity discretion that currently allows for regional variations without review or oversight. We also find that NERC's definition satisfies the Commission's technical concerns in Order No. 743 through the use of a bright-line 100 kV threshold, with specific inclusions and exclusions within the definition, for identifying bulk electric system elements and the establishment of an exception process for facilities that are not necessary for operating the interconnected transmission network.

41. Moreover, we are not persuaded by the rationale of the commenters who advocate that we remand the NERC proposal. We disagree with NYPSC that the proposed definition will likely result in classifying certain facilities as part of the bulk electric system despite their being unnecessary for operating an interconnected transmission network. An entity that believes its facility is improperly classified as part of the bulk electric system by application of the definition may avail itself of the exception process to have the facility removed from inclusion in the definition. With regard to NYPSC's claim that there is no technical justification for the 100 kV threshold, in Order No. 743, the Commission found "that many facilities operated at 100 kV and above have a

significant effect on the overall functioning of the grid and that the majority of 100 kV and above facilities in the United States operate in parallel with other high voltage and extra high voltage facilities, interconnect significant amounts of generation sources and operate as part of a defined flowgate.” The Commission explained that this “illustrates their parallel nature and therefore their necessity to the reliable operation of the interconnected transmission system” and that “[p]arallel facilities operated at 100-200 kV will experience similar loading as higher voltage parallel facilities at any given time and the lower voltage facilities will be relied upon during contingency scenarios.”³⁴ In addition, in Order No. 743 the Commission identified the reliability concerns created by the current definition and a method to ensure that certain facilities needed for the reliable operation of the nation’s bulk electric system are subject to mandatory and enforceable Reliability Standards. The Commission noted that the material impact assessments implemented, for example, by NPCC “are subjective in nature, and results from such tests are inconsistent in application, as shown through the exclusion of facilities that clearly are needed for reliable operation.”³⁵ The Commission also found that the vast majority of 100 kV and above facilities are part of parallel networks with high voltage and extra high voltage facilities and are necessary for reliable operation.³⁶ Thus, the Commission found

³⁴ Order No. 743, 133 FERC ¶ 61,150 at P 73.

³⁵ Order No. 743, 133 FERC ¶ 61,150 at P 96.

³⁶ *Id.*

that NERC should “establish a uniform definition that eliminates subjectivity and regional variation in order to ensure reliable operation of the bulk electric system” and that “the existing NPCC impact test is not a consistent, repeatable, and comprehensive alternative to the bright-line, 100kV definition we prefer.”³⁷

42. NERC already applies a general 100 kV threshold, and today all regions, with the exception of NPCC, also apply a 100 kV threshold. We also note NYPSC cites to the same methodology that the Commission found dubious in Order No. 743-A where the Commission explained that it had:

serious concerns about NPCC’s [] methodology. The Commission stated that, as a threshold matter, the material impact tests proffered by commenters did not measure whether specific system elements were necessary for operating the system, but, rather, measure the impact of losing the element. The Commission’s extensive discussion of the NPCC test further noted that the NPCC methodology is unduly subjective, and results in an inconsistent process that excludes facilities necessary for operating the bulk electric system from the definition.³⁸

43. We also disagree with NYPSC’s contention that this approach presumes the Commission has jurisdiction over all facilities operated at 100 kV or above, unless proven otherwise, which inappropriately shifts the legal and technical burdens to the states. As noted above and in Order No. 743-A, the suggested solution of a 100 kV

³⁷ *Id.*

³⁸ Order No. 743-A, 134 FERC ¶ 61,210 at P 47 (footnotes omitted) (citing Order No. 743, 133 FERC ¶ 61,150 at PP 74, 76 and 85).

threshold paired with an exemption process, in essence, “merely clarifies the current NERC definition, which classifies facilities operating at 100 kV or above as part of the bulk electric system.”³⁹ Thus, we are not persuaded that NERC’s proposal inappropriately shifts legal or technical burdens. In addition, the Commission has maintained that the bright-line threshold would be a “first step or proxy” in determining which facilities should be included in the bulk electric system. The definition, coupled with the exception process will ensure that facilities not necessary for the operation of the interconnected transmission network will be properly categorized. Further, the Commission’s approach for determining whether elements are used for local distribution on a case-by-case basis, as discussed more fully below, addresses NARUC’s concerns as to the status of local distribution elements that are not also described in exclusion E3 and that the definition does not appropriately reflect the statutory limits of the Commission’s authority under FPA section 215 as well as NYPSC’s concern about the Commission having jurisdiction over all facilities operated at 100 kV or above. With regard to the specific examples cited by NYPSC, we find that such determinations are more appropriate for the exception process and beyond the scope of this proceeding.

44. We also disagree with NYPSC and Massachusetts DPU that NERC’s proposal is flawed because NERC’s petition did not include a formal cost analysis. Order No. 743 did not require such an analysis. Rather, Order No. 743 tasked NERC with certain

³⁹ Order No. 743-A, 134 FERC ¶ 61,210 at P 36.

directives and NERC's petitions are intended to comply with those directives. In addition, while cost of implementation can be relevant in Commission review of a proposed Reliability Standard, the foremost concern is the reliability of the interconnected transmission network.⁴⁰ Therefore, we find that NERC's petition adequately addresses the Commission's Order No. 743 directives.

B. The Core Definition of Bulk Electric System

NOPR Proposal

45. In the NOPR, the Commission proposed to approve the bulk electric system "core" definition developed by NERC which states as follows:

Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

In the NOPR, the Commission noted that NERC's proposal appears to satisfy the objectives set forth in Order No. 743. The Commission also stated that NERC's "core" definition establishes the fundamental threshold for inclusion of facilities in the bulk electric system as those that are operated at 100 kV or higher, if they are transmission elements, or are connected at 100 kV or higher, if they are real power or reactive power resources. In addition, the Commission stated that the core definition also establishes a 100 kV criterion as a bright-line threshold, rather than as a general guideline as in the

⁴⁰ See Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 330.

current definition, i.e., the phrase “generally operated at” in the current definition is eliminated.

Comments

46. NERC and a majority of commenters including most trade organizations believe that the core definition satisfies the Order No. 743 directives. By eliminating the language “as defined by the Regional Reliability Organization” and “generally operated at,” they state that the revised definition eliminates the subjectivity and regional variations that are possible under the current definition.⁴¹ WPPC supports the NERC proposals but is concerned that the NOPR could be read as attempting to impose nationally uniform standards without allowing regional variation. WPPC believes that FPA section 215 requires deference to Regional Entities in developing Reliability Standards and is concerned that the NOPR’s references to uniformity of the definition of bulk electric system must be limited by the deference accorded to Regional Entities in the statute.

47. Other commenters seek modification of the core definition. For example, PSEG Companies believe that the core definition will introduce subjectivity because it omits facilities and systems necessary to operate the facilities above 100 kV, such as protection

⁴¹ See *e.g.*, NERC, APPA, EEI, NRECA, ELCON, the Regional Entities, NV Energy, National Grid, Southern Companies, Duke Energy, International Transmission Company, TAPS, BPA, Hydro One and IESO, and Snohomish.

systems, underfrequency load shedding systems and control centers.⁴² PSEG Companies suggest the addition of demand response above 75 MW within a balancing authority into the definition. In the same vein, ISO New England suggests including capacity resources connected below 100 kV and identifies protection systems, under-frequency and under-voltage load shedding systems, inclusion of non-bulk electric system facilities into transmission and operational planning, and control rooms as items that are important to operating the bulk electric system but not in the definition. ISO New England, therefore, believes that NERC should make the determination whether or not these facilities and control systems must comply with Reliability Standards independent of their designation. Valero seeks clarification that the core definition excludes elements “that are owned and used by an industrial end-user to serve its load.”⁴³

48. Similarly, IUU and Barrick state that industrial generators are intrastate facilities that serve only the owner’s load and believe that they are excluded from the jurisdiction of the Commission.⁴⁴ IUU and Barrick believe that some of the Reliability Standards appear to reach beyond the limits imposed by Congress and into these intrastate industrial generator facilities. According to IUU and Barrick, the definition needs an additional exclusion that excludes these intrastate facilities.

⁴² PSEG Comments at 4-6.

⁴³ Valero Comments at 3.

⁴⁴ *See also* Barrick Reply Comments at 2-3.

49. Several commenters that support the NERC proposal also comment on matters not specifically raised in the NOPR. APPA recommends that the Commission state that it expects NERC will continue to treat the Phase 2 bulk electric system definition project as a priority in the 2013 budget year. APPA also requests that the Commission direct NERC to expedite the deregistration process for those entities or facilities that are no longer designated as part of the bulk electric system under the new definition or through application of the Rules of Procedure exception process. APPA believes that an expedited deregistration process would reduce the associated burden on entities that are no longer required to document compliance due to the revisions in the bulk electric system definition and the exception process.

50. Redding requests that, due to the connection between the definition and the NERC Functional Model, the Commission should direct revisions to the NERC Functional Model to accommodate entities that own or operate facilities that technically qualify as transmission but that have a limited, if any, impact on reliability.

Commission Determination

51. We find that the “core” definition satisfies the Order No. 743 directives to remove the subjectivity and regional variations that are possible under the current definition by eliminating the language “as defined by the Regional Reliability Organization” and “generally operated at,” in the revised definition. The “core” definition, quoted above, establishes the fundamental threshold for inclusion of facilities in the bulk electric system as those that are operated at 100 kV or higher, if they are transmission elements, or are connected at 100 kV or higher, if they are real power or reactive power resources. The

core definition also establishes a 100 kV criterion as a bright-line threshold, rather than as a general guideline as in the current definition, i.e., the phrase “generally operated at” in the current definition is eliminated. The core definition also continues to capture equipment associated with the facilities included in the bulk electric system.

52. Other than the directive to modify exclusion E3 as discussed below, the Commission declines to direct NERC to further modify the definition or the specified inclusions and exclusions. Specifically, we will not direct further revisions to address demand response, protection systems and other facilities or equipment as separate inclusions or exclusions as advocated by ISO New England, PSEG Companies, IUU or Barrick.⁴⁵ Rather, NERC has indicated that it has initiated a Phase 2 of the development project for the definition of bulk electric system, and interested stakeholders have the opportunity in the first instance to raise their ideas in that forum regarding possible additions, inclusions and exclusion set forth in the bulk electric system definition.⁴⁶

⁴⁵ We note that, in Order No. 693, the Commission recognized demand side management as a type of resource for contingency reserve that should be treated on a comparable basis with other resources; and must meet similar technical requirements as other resources providing this service. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 330-335.

⁴⁶ According to NERC, due to time constraints in meeting the compliance deadline set in Order No. 743, NERC separated the development of the revised definition into two phases. See NERC Petition at 46. NERC stated that Phase 1 culminated in the language of the proposed modified definition that is the primary subject of this Final Rule. Phase 2, which is ongoing, intends to focus on other industry concerns raised during Phase 1.

53. Moreover, in the NOPR we acknowledged NERC's statement that the core definition also continues to capture equipment associated with the facilities included in the bulk electric system.⁴⁷ In the NOPR we agreed with NERC that while the new definition does not use the term "associated equipment," the phrase is included in the definition through the defined term "Transmission Elements."⁴⁸ We adopt the NOPR proposal that the term "associated equipment," is included in the definition through the defined term "Transmission Elements" which could include the facilities identified by PSEG Companies.

54. With regard to Valero's clarification, that the core definition excludes elements "that are owned and used by an industrial end-user to serve its load," Valero can either seek to have this matter addressed generically, if appropriate, in NERC's Phase 2, or seek to have this addressed on a case-by-case basis in the exception process that we approve in this Final Rule.

55. We decline, as APPA requests, to direct NERC to expedite the deregistration process for those entities who own or operate facilities that are no longer designated as part of the bulk electric system. We do not expect there to be significant numbers of entities either needing to register or deregister due to the change in definition.⁴⁹ To the

⁴⁷ NOPR, 139 FERC ¶ 61,247 at PP 16, 55.

⁴⁸ NOPR, 139 FERC ¶ 61,247 at P 55 n.69.

⁴⁹ See NOPR, 139 FERC ¶ 61,247 at P 132.

extent entities seek to deregister, NERC, as the ERO, can determine the appropriate timeframe for making such a determination. We also decline to order NERC to modify the Functional Model as Redding requests as the issues Redding raises are outside the scope of this proceeding. In response to WPPC's concern, this Final Rule adopts the revised definition which eliminates regional discretion for determining whether an element is part of the bulk electric system. It does not address or subsume the ability of Regional Entities to develop Reliability Standards for their regions that meet criteria for regional Reliability Standards.

56. In summary, the Commission finds that NERC's proposal adequately addresses the concerns articulated in Order No. 743 regarding regional discretion and the need for a consistent approach and satisfies the concerns regarding the elimination of inconsistencies across regions.

C. Local Distribution

NOPR Proposal

57. The NOPR noted that, although Order No. 743 acknowledged that "Congress has specifically exempted 'facilities used in the local distribution of electric energy'" it still is necessary to determine which facilities are local distribution, and which are transmission.⁵⁰ The NOPR observed that Order No. 743-A stated that "[w]hether facilities are used in local distribution will in certain instances raise a question of fact,

⁵⁰ Order No. 743-A, 134 FERC ¶ 61,210 at P 67.

which the Commission has jurisdiction to determine.”⁵¹ In addressing what constitutes local distribution, NERC stated in its petition that facilities used for the local distribution of electric energy are expressly excluded from the bulk electric system by the core definition as well as by the local network exclusion, exclusion E3.⁵² In the NOPR, the Commission requested comment regarding how NERC’s proposed definition is responsive to the Commission’s directives in Order Nos. 743 and 743-A. Specifically, the Commission requested comment on how NERC’s proposal adequately differentiates between local distribution and transmission facilities in an objective, consistent, and transparent manner.

Comments

58. NERC and numerous commenters state that the definition adequately differentiates between local distribution and transmission.⁵³ NERC states that the revised definition distinguishes between bulk electric system facilities and non-bulk electric system facilities and local distribution facilities fall into the latter category.⁵⁴ NERC adds that, by applying the definition, facilities used for local distribution will not be included

⁵¹ NOPR, 139 FERC ¶ 61,247 at P 58, *quoting* Order No. 743-A, 134 FERC ¶ 61,210 at P 67.

⁵² NOPR, 139 FERC ¶ 61,247 at P 59, (citing NERC BES Petition at 16).

⁵³ *See e.g.*, APPA Comments at 8-9, EEI Comments at 4, NRECA Comments at 7, Hydro One Comments at 3, NV Energy Comments at 3-4, PHI Companies Comments at 3, TAPS Comments at 3, BPA Comments at 3, WPPC Comments at 27-30.

⁵⁴ NERC Comments at 6.

due to their specific exclusion in the core definition. NERC and others also state that the exception process can be used to determine whether facilities are used for local distribution when an entity believes such facilities have been improperly included.⁵⁵

59. While ELCON generally agrees with NERC's position, ELCON comments that NERC's proposal does not fully respond to the Commission's directive in Order Nos. 743 and 743-A. ELCON maintains that a definition of "local distribution" is necessary to avoid including assets that are clearly used for the local distribution as part of the bulk electric system. ELCON expresses concern that industrial consumers' equipment that is rated 100 kV or above will be designated as a component of the bulk electric system, irrespective of whether such elements are material for the reliable operation of the interconnected Bulk-Power System. ELCON recommends that the Commission address this issue by establishing a joint working group with NARUC to draft a proposed definition of local distribution to exclude certain facilities from the scope of the definition of bulk electric system.

60. Some entities that generally agree with NERC also suggest clarifications to improve the distinction between local distribution and transmission. MISO suggests that, to identify local distribution facilities, the Commission direct NERC to clarify the last sentence of the core definition by "cross-referencing" the exclusion criteria in the

⁵⁵ See *e.g.* WPPC Comments at 28.

definition.⁵⁶ Snohomish requests that the Commission clarify that the Seven Factor Test established in Order No. 888 is one element that can be used to evaluate an exception request in addition to other engineering and technical considerations.⁵⁷

61. Other commenters contend that NERC's proposal does not adequately differentiate between local distribution and transmission facilities or reflect the statutory limits of the Commission's authority under FPA section 215.⁵⁸ As noted above, NARUC states that the NERC definition does not appropriately reflect the statutory limits of the Commission's authority under Federal Power Act Section 215 and its implementation could unnecessarily overreach into state jurisdictional local distribution facilities. NARUC maintains that, while the definition of bulk electric system appears to exclude local distribution by restating the law, the definition does not go far enough to ensure that a costly analysis applying for an "exception" is not required to be performed with regard to local distribution elements that are by law "excluded." NARUC contends that the mere fact that a subset of local distribution elements expressly excluded from the bulk electric system by the core definition are specifically identified in exclusion E3 could cause confusion as to the status of local distribution elements that are not also described in E3. Similarly, the Steel Manufacturers Association states that the Commission cannot

⁵⁶ MISO Comments at 4.

⁵⁷ Snohomish Comments at 3.

⁵⁸ *E.g.*, NARUC, Holland, NYPSC, and SmartSenseCom.

allow NERC's exception process to determine the boundaries of the Commission's jurisdiction.

62. Consumers Energy believes that the definition does not differentiate between transmission and local distribution because "Transmission Elements" and "local distribution" are undefined. Consumers Energy states that the Commission should clarify that any facilities that have been found by the Commission to be local distribution pursuant to the Seven Factor Test are also local distribution under FPA section 215 and therefore outside the bulk electric system.⁵⁹ Consumers references a prior Commission declaratory order accepting the Michigan Public Service Commission's determination of transmission and local distribution facilities.⁶⁰ Consumers notes that it sold all of its "bulk electric system elements" to Michigan Electric Transmission Company, who is the registered transmission owner. ITC Companies and MISO filed reply comments requesting that the Commission reject the coordination and continuity aspect of Consumers' proposal to automatically exclude from the definition those facilities that are "in series" with transmission facilities that are included in the bulk electric system definition.⁶¹ In addition, they state that this is not the proper proceeding to address

⁵⁹ Consumers Comments at 3-8.

⁶⁰ Consumers Comments at 4 (citing July 29, 1998 letter order in Docket No. EL98-21-000).

⁶¹ ITC Reply Comments at 6-7.

whether specific facilities may or may not be part of the bulk electric system. Consumers filed a motion to strike the MISO reply comments.

63. Portland is concerned that the Commission is assessing its reliability jurisdiction without addressing “the inconsistency between its reliability jurisdiction and its traditional ‘transmission’ jurisdiction under FPA section 201(b).” Portland states that the Commission could clarify that for entities who apply the local distribution exception in good faith, any future regulatory determination that such distribution facilities are to be treated as part of the bulk electric system within the scope of FPA section 215 regulation will be prospective only.⁶²

64. Holland argues that, aside from the exclusions in the core definition, there are no criteria or guidelines that exclude local distribution facilities from the bulk electric system. Holland also argues that if an entity challenges a registration, there is no guidance as to what information NERC will consider whether to recognize the facilities in question as local distribution and exclude them from the bulk electric system. Holland contends that the proposed Rules of Procedure fail to provide any distinction between those facilities that must be excluded because they are local distribution versus those that should be excluded because, although they meet the [bulk electric system] bright-line criteria, they are not necessary for the reliable operation of the interconnected transmission system. Holland claims that the exception process does not make “any

⁶² Portland Comments at 4.

distinction between criteria necessary for determining those facilities that must be excluded because they are local distribution versus those that should be excluded because they [] meet the [bulk electric system] criteria, but are not material.”⁶³ Holland adds that “because the exclusions are not comprehensive, and because the ‘exceptions’ process provides no further guidance on the proper exclusion of these facilities, there would be no basis to support a conclusion that the NOPR has effectively and transparently identified, let alone justified, a second class or test for identifying local distribution for purposes of Section 215 of the FPA.”⁶⁴ Similarly, Massachusetts DPU comments that exception requests will inevitably involve difficult questions regarding whether a facility is “used in the local distribution of electric energy,” an area over which states have exclusive authority under the FPA.⁶⁵

65. Valero requests that the Commission direct NERC to develop criteria based on a “primary function test” to exclude facilities used in local distribution. In addition, Valero states that the Commission should “provide guidance to NERC by [] stating that, to constitute distribution, a facility need not be used *exclusively* for distribution purposes.”⁶⁶ Further, Valero contends that NERC’s “distribution use only” position contradicts the

⁶³ Holland Comments at 6.

⁶⁴ Holland Comments at 9. *See also* Barrick Reply Comments at 2.

⁶⁵ Massachusetts DPU Comments at 10.

⁶⁶ Valero Comments at 8-12 (emphasis in original) (citing *Detroit Edison v. FERC*, 334 F.3d 48, 54 (D.C. Cir. 2003)).

plain language of sections 201 and 215 of the FPA. Valero states that its “discrete on-site electrical equipment” is designed only to serve load at its refineries. While the facilities may enhance the reliability of electric service, Valero asserts they are only used by an industrial end-user of electricity for “the local distribution of electric energy” and must be excluded from the bulk electric system. The Power Agencies ask for clarification of footnote 79 in the NOPR and assume that the Commission is clarifying that certain facilities may not satisfy the revised definition, but may constitute transmission facilities for purposes other than applying FPA section 215.⁶⁷

Commission Determination

66. For the reasons discussed below, we find that NERC’s “core” definition of bulk electric system definition, together with exclusion E3 (local networks), is consistent with the section 215 exclusion of local distribution facilities. We also find that, while NERC’s case-by-case exceptions process is appropriate to determine the technical issue of whether facilities are part of the bulk electric system, the jurisdictional question of whether facilities are used in local distribution should be decided by the Commission.

67. NERC’s “core” definition provides a 100 kV threshold for determining whether elements or facilities are included in the bulk electric system. As we indicated in Order No. 743, the 100 kV threshold is a reasonable “first step or proxy” for determining which facilities should be included in the bulk electric system. Indeed, it is reasonable to

⁶⁷ See NOPR, 139 FERC ¶ 61,247 at P 60 n.79 stating that “an element that falls outside of the definition of bulk electric system is not necessarily local distribution.”

anticipate that this threshold will remove from the bulk electric system the vast majority of facilities that are used in local distribution, which tend to be operated at lower, sub-100 kV voltages. Moreover, applying the four exclusions in NERC's proposed definition should serve to further exclude facilities used in local distribution from the bulk electric system. In particular, as NERC indicates, exclusion E3 (local networks) – although not synonymous with local distribution - should serve to reasonably exclude many above-100 kV facilities that are used in local distribution. Based on the information provided in NERC's petition, as well as the supporting comments of EEI and others, we anticipate that the "core" definition together with exclusion E3 should provide a reasonable means to accurately and consistently determine on a generic basis whether facilities are part of the bulk electric system. In other words, most local distribution facilities will be excluded by the 100 kV threshold or exclusion E3 without needing to seek a Commission jurisdictional determination. Accordingly, we find this aspect of NERC's petition reasonable.

68. In addition to the definition, NERC also submitted revisions to the Rules of Procedure (discussed below in greater detail) that allow for a case-by-case exception process. Included in this process is an opportunity for entities to seek to exclude facilities from the bulk electric system because they are used in local distribution. NERC's petition does not provide criteria or guidance that it would apply in the case-by-case exception process to determine whether an element above 100 kV should be excluded as

local distribution, as directed in Order No. 743.⁶⁸ Thus, we cannot conclude that the case-by-case exception process will “adequately differentiate[] between local distribution and transmission facilities in an objective, consistent, and transparent manner.”⁶⁹

69. In Order No. 743, the Commission stated that determining the line between transmission and local distribution should be part of the exception process and left it to NERC in the first instance to determine how to make such a determination.⁷⁰

After further review of NERC’s proposal in this proceeding, and upon consideration of the comments submitted, we believe that it is more appropriate that the Commission make such case-by-case jurisdictional determinations when necessary, and to apply the Seven Factor Test set forth in Order No. 888 to make such determinations. The determination whether an element or facility is “used in local distribution,” as the phrase is used in the FPA, requires a jurisdictional analysis that is more appropriately performed

⁶⁸ The Commission, in Order No. 743-A, explained that “the Seven Factor Test could be relevant and possibly is a logical starting point for determining which facilities are local distribution for reliability purposes, while also allowing NERC flexibility in applying the test or developing an alternative approach as it deems necessary.” Order No. 743-A, 134 FERC ¶ 61,210 at P 69. NERC, in its petition, did not adopt a specific test or criteria for determining whether a facility is local distribution, but indicated that an entity seeking an exception for local distribution facilities could provide a “seven factor” analysis as one means to support the petition. NERC BES Petition at 49.

⁶⁹ See NOPR, 139 FERC 61,247 at P 59.

⁷⁰ Order No. 743, 133 FERC ¶ 61,150 at P 38.

by the Commission.⁷¹ Further, Commission review of whether a facility is used in local distribution comports with relevant legal precedent. As we explained in Order No. 743-A, “[w]hether facilities are used in local distribution will in certain instances raise a question of fact, which the Commission has jurisdiction to determine.”⁷²

70. As noted above, application of the “core” definition and the four exclusions should serve to exclude most facilities used in local distribution from the bulk electric system. However, there may be certain circumstances that present a factual question as to whether a facility that remains in the bulk electric system after applying the “core” definition and the four exclusions should nonetheless be excluded because it is used in local distribution. In such circumstances, which we expect will be infrequent, an entity must petition the Commission seeking a determination that the facility is used in local

⁷¹ *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 803 (2003), *order on reh’g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh’g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh’g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff’d sub nom. Nat’l Ass’n of Regulatory Util. Comm’rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008)(“‘Local distribution’ is a legal term; under FPA Section 201(b)(1), the Commission lacks jurisdiction over local distribution facilities.”).

⁷² Order No. 743-A, 134 FERC ¶ 61,210 at P 67 and n.78, (citing *California Pacific Electric Co., LLC*, 133 FERC ¶ 61,018 at n.59 (2010) (citing *FPC v. Southern California Edison Co.*, 376 U.S. 205, 210 n.6 (1964) (asserting that “the Supreme Court has determined that whether facilities are used in local distribution involves a question of fact to be decided by the [Commission] as an original matter.”))). *See also Connecticut Light & Power Co. v. Federal Power Commission*, 324 U.S. 515, 534-35 (1945).

distribution.⁷³ Such petitions should include information that will assist the Commission in making such determination, and notice of the petition must be provided to NERC and relevant Regional Entities.

71. In addressing such petitions, the Commission will apply the Seven Factor Test set forth in Order No. 888. In Order No. 888, the Commission articulated the Seven Factor Test to determine, on a case-by-case basis, whether a facility is a local distribution facility or a transmission facility.⁷⁴ However, the Commission has found that the factors identified in the Seven Factor Test are not exclusive when determining whether an element is used for local distribution. Specifically, the Commission recognized that the Seven Factor Test does not resolve all possible issues and that “there may be other factors that should be taken into account in particular situations.”⁷⁵ The Commission will apply a similar analysis in determining in the context of FPA section 215 whether a facility is used in local distribution. In other words, while the starting point for the Commission’s analysis will be an analysis based on the Seven Factor Test, the Commission will consider other factors that should be taken into account in particular situations.

⁷³ Such petitions will be assigned an “RC” docket prefix. The determinations would be public proceedings subject to notice and comment requirements which will allow NERC and interested parties (including state regulators) to provide input on a petition.

⁷⁴ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,771, 31,783-84, Appendix G.

⁷⁵ Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,242.

72. To reiterate, we expect that the 100 kV threshold as a “first step or proxy” for determining which facilities should be included in the bulk electric system, plus the four exclusions (in particular the local network exclusion E3), will exclude many facilities that are used in local distribution and thus should be excluded from the bulk electric system. This approach recognizes that, although local distribution facilities are excluded from the definition, it still may be necessary to determine which facilities are local distribution, and which are transmission. Whether facilities are used in local distribution will in certain instances raise a question of fact, which the Commission has jurisdiction to determine. We decline to clarify, as Portland requests, that for entities who apply the local distribution exception in good faith, any future regulatory determination that such distribution facilities are to be treated as part of the bulk electric system within the scope of FPA section 215 regulation will be prospective only. As explained above, in circumstances where a factual question remains after applying the “core” definition and the exclusions, entities must apply to the Commission for a determination of whether an element is used in local distribution. We believe this approach provides a means to maintain consistency and transparency across the various reliability regions but still have the necessary flexibility to make case-by-case determinations appropriate for reliability.

73. To the extent the various reply comments by ITC Companies, MISO and Consumers raise questions about the status of specific facilities, we decline to address them in this Final Rule as this rulemaking proceeding is not the proper forum to decide such matters.

D. Inclusions and Exclusions in the Definition of Bulk Electric System**NOPR Proposal**

74. In the NOPR, the Commission proposed to approve, in addition to the core definition, specific inclusions and exclusions because the inclusions and exclusions provide added clarity regarding which elements are part of the bulk electric system as compared to the existing definition. In the NOPR, the Commission also posed questions about how some of the inclusions and exclusions will be applied to better understand potential applications of the inclusions and exclusions, their effect on identifying the facilities or elements for bulk electric system reliability, and whether possible gaps exist. We address these questions below.

1. Inclusion I1 (Transformers)**NOPR Proposal**

75. Inclusion I1 includes as part of the bulk electric system “[t]ransformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under [the radial system or local network exclusion].” In its petition, NERC explained that, due to transformers having multiple windings operating at differing voltages, the intent of inclusion I1 includes transformers operating at 100 kV or higher on the primary winding and at least one secondary winding.⁷⁶

⁷⁶ NERC BES Petition at 17.

76. In the NOPR, the Commission stated that NERC's approach to inclusion I1 "is a reasonable approach to identifying transformers that are appropriately included as part of the bulk electric system."⁷⁷ However, the Commission expressed concern whether a particular transformer – operated at 100 kV or higher on the primary winding but all secondary terminals are operated below 100 kV – should be part of the bulk electric system or whether the exception process would be sufficient to include these transformers.⁷⁸ The Commission also requested comment on whether transformers that have a terminal operated at 100 kV or above on the high side and below 100 kV on the low side should be designated as part of the bulk electric system.

Comments

77. NERC supports allowing the exception process to include the transformers described by the Commission. NERC states that the "vast majority" of transformers with low side voltages step down to a voltage class that is designed for distribution to load. NERC adds that the 100 kV threshold for secondary windings provides a "clear demarcation" between facilities used to transfer power as opposed to those that serve load. According to NERC, while there are instances where transformers with secondary windings below 100 kV are connected in parallel with high voltage transmission lines, it

⁷⁷ NOPR, 139 FERC ¶ 61,247 at P 63.

⁷⁸ In the NOPR the Commission noted that the joint NERC and Commission staff report on the September 8, 2011, Arizona-Southern California blackout explains how transformers of this type were not monitored or analyzed by the reliability coordinator, transmission operators and balancing authorities. NOPR, 139 FERC ¶ 61,247 at P 63.

is not possible to craft a bright-line inclusion of such transformers because the distinction may hinge on function as opposed to the physical characteristics of the transformer.

NERC states that the exception process can evaluate whether such transformers should be included in the bulk electric system. A majority of commenters share NERC's position and believe that most transformers with the configuration described by the Commission in the NOPR do not impact the bulk electric system and those that do can be classified as part of the bulk electric system through the exception process.⁷⁹

78. SoCal Edison agrees with NERC, but identifies transformers operated in parallel with the bulk electric system as those that should be designated as part of the bulk electric system irrespective of the operational voltage of the transformer. SoCal Edison argues that information regarding such transformers should be provided to the impacted entities, e.g., reliability coordinators and neighboring regional entities. SoCal Edison contends that including these types of transformers in the bulk electric system would have made the Regional Entities, reliability coordinators, transmission operators and balancing authorities aware of the contingencies of the transformers and their impact on the bulk electric system in the September 2011 blackout.

79. SmartSenseCom states that transformers that operate at 100 kV or above with any secondary windings below 100 kV should be included. On the other hand, Consumers does not support inclusion I1 because it goes beyond the Commission's jurisdiction and

⁷⁹ *E.g.* APPA, EEI, ELCON, WREA, Anaheim, Riverside, Imperial Irrigation District, G&T Cooperatives, NV Energy, NESCOE, and TAPS.

would confuse the distinction between the bulk electric system and local distribution.

Consumers argues that inclusion I1 may create a “moving registration target” if related facilities are added to the bulk electric system.⁸⁰

Commission Determination

80. We find that inclusion I1 is a reasonable approach to identifying transformers that are appropriately included as part of the bulk electric system. We agree with NERC that inclusion I1 includes transformers operating at 100 kV or higher on the primary winding and at 100 kV or higher on at least one secondary winding. With regard to the Commission’s concern in the NOPR about inclusion of a transformer that is operated at 100 kV or higher on the primary winding but all secondary terminals are operated below 100 kV, we agree with NERC that it is appropriate for such transformers to be considered for inclusion through the exception process. We are persuaded that transformers with low side voltages stepped down to a voltage class that is designed to distribute power to load and, therefore, the 100 kV threshold for secondary windings provides an initial screening between facilities used to transfer power as opposed to those that serve load. We agree with NERC’s assessment that crafting an inclusion for transformers described by the Commission is difficult because the distinction may hinge on function as opposed to the physical characteristics of the transformer. Therefore, we decline to include such transformers in inclusion I1.

⁸⁰ Consumers Comments at 9-10.

81. With regard to the specific configurations identified by SoCal Edison (transformers that operate in parallel with the bulk electric system irrespective of the operational voltage of the transformer), we will not make a determination of general application. Rather, such matters should be addressed in the case-by-case exception process.

82. We do not agree with Consumers that inclusion I1 would be ineffective because it would include lower voltage distribution facilities that were not designed to provide reliability to the bulk electric system or prevent cascading outages. The 100 kV threshold for secondary windings provides a bright line between facilities used to transfer power as opposed to those that serve load, and if a transformer is included pursuant to inclusion I1, but an entity believes it is not necessary for operation of the interconnected transmission network, it may be considered for exclusion through the exception process.

2. Inclusion I2 (Generating Resources)

NOPR Proposal

83. Inclusion I2 of the bulk electric system definition provides for specific inclusion of generating resources with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA. NERC developed this inclusion based on the text of the Registry Criteria for generating units while

providing clarity by including “the generator terminals through the high-side of the step-up transformer connected at a voltage of 100 kV or above.”⁸¹

84. In the NOPR, the Commission agreed that inclusion I2 is consistent with the individual and aggregate nameplate rating thresholds set forth in the Registry Criteria but noted the differing descriptions of the connection point of the generating resources.⁸²

Inclusion I2 specifies “generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above,” and the Registry Criteria specifies a “direct connection” to the Bulk-Power System. Accordingly, the Commission requested comment whether inclusion I2 will result in a material change to registration of existing generating units due to the difference in the language regarding the connection point. The Commission also requested comment if a generating unit, with a gross individual nameplate rating greater than 20 MVA connected through the high-side of the step-up transformer connected at a voltage of 100 kV or above when the low side of the transformer is less than 100 kV, is included in the bulk electric system pursuant to inclusion I2. Further, the Commission asked how this result differs for a generation resource with two or more step-up transformers where the last transformer in the series operates at 100 kV or above.

⁸¹ NERC BES Petition at 17.

⁸² NOPR, 139 FERC ¶ 61,247 at P 65.

Comments

85. Most commenters do not believe that inclusion I2 will materially change registration of generating resources. NERC states that inclusion I2 connection point language merely clarifies the “directly connected” language in the Registry Criteria. NERC explains that while most generation is connected through a unit transformer on the high voltage bus within a facility, there are instances where generators are connected to lower voltages within a facility. NERC adds that most of these types of configurations are in older facilities where the higher voltage bus was added after the original generators. NERC confirms that the specific scenario described by the Commission would result in the generator being included in the bulk electric system provided that the transformers reside within a single site boundary and are used only to step-up the output voltage of the generator.⁸³ APPA and others agree with NERC’s view. APPA adds that, if the transformers in question are also used to deliver power to serve local load, the generation resources and transformers should be excluded from the bulk electric system.⁸⁴ PSEG Companies believe that inclusion I2 addresses the issue regarding two step-up transformers in series. PSEG Companies explain that both step-up transformers are part of the generator per inclusion I2 if the purpose of the transformers is to solely step-up the output voltage.

⁸³ NERC Comments at 9-10. *See also* comments of EEI.

⁸⁴ APPA Comments at 14-15. *See also* comments of National Grid, TAPS, NESCOE, and G&T Cooperatives.

86. Arizona Public Service requests that the Commission clarify whether the voltage connection language in inclusion I2 applies only to the aggregated 75 MVA threshold or also to the 20 MVA threshold for individual generating units. Southern Companies believe that there are instances where generators may be connected to lower voltages that may fit under inclusion I2 but would not necessarily fit in the Registry Criteria.

87. Some commenters do not support inclusion I2 for varying reasons. Dominion opposes inclusion of elements such as those provided for in inclusion I2 that are already subject to reliability standards because the element meets the criteria in the NERC Compliance Registry. ISO New England states that the connection language in inclusion I2 should be eliminated. ISO New England maintains that interpreting inclusion I2 to be based on generator plant size, independent of the voltage connection, is important from a generator stability modeling view point. This is because generators connected at voltages less than 100 kV can have a significant impact on system stability.⁸⁵ ISO New England supports adding generators connected at lower voltages but not the system to which the generators are connected. ISO New England believes that adding generators, regardless of their connection voltage levels, would increase the universe of registered generators and would enhance reliability.

88. MISO recommends that the Commission clarify that operators of generating resources included through inclusion I2 will only be subject to Reliability Standards for

⁸⁵ ISO New England Comments at 4.

generators unless a specific determination is made that other standards should apply to a particular piece of equipment. MISO believes that, without this clarification, inclusion I2 could increase the number of transmission operators by including generation equipment.

89. Barrick believes that the term “gross plant/facility” in inclusion I2 needs to be clarified. Barrick states that it is not clear whether the terms are based on geographic proximity or structural definition. Barrick is also concerned that inclusion I2 is based on “gross” rating while exclusion E2 is based on net capacity and exclusion E3(a) is based on a non-retail basis, and that read together inclusion I2 and exclusions E2 and E3(a) appear to be in conflict.⁸⁶ In reply comments, Barrick suggests that, instead of focusing on nameplate ratings, the focus should be on the normal configuration and operation of generation.

90. SmartSenseCom states that the Commission should direct NERC to modify inclusion I2 to include generating units that are stepped up to 100 kV or above containing a transformer with a low side below 100 kV because, at these levels, generating resources should be presumed to impact reliability. SmartSenseCom contends that Reliability Standards should apply to such facilities “in light of their potential impact to system reliability, especially given the increasing levels of distributed generation penetration that is expected in the near future.”⁸⁷ Springfield questions whether multiple individual units

⁸⁶ Barrick Comments at 10.

⁸⁷ SmartSenseCom Comments at 12.

are considered one unit if they have a shared bus. Springfield believes that such instances should not be considered individually.

Commission Determination

91. The Commission approves inclusion I2. Based on the language of inclusion I2, its derivation from the Registry Criteria and the statements from NERC and commenters, the Commission concludes that application of inclusion I2 will not materially change registration of generating resources. The Commission accepts NERC's explanation that the inclusion I2 connection point language merely clarifies the "directly connected" language in the NERC Registry Criteria, section III.c.1. Further, the Commission agrees with NERC and other commenters that multiple step-up transformers that are solely used to deliver the generation to the bulk electric system at 100 kV or above qualify the generator and the step-up transformers pursuant to inclusion I2.

92. APPA and commenters claim that, if a transformer is also used to deliver power to serve local load, through, for example a 69 kV network, the generation resources and transformers should be excluded from the bulk electric system. The Commission agrees with the specific example. In such cases, local load refers to end-user load and not generator-specific station service load. This example depicts a generator whose step-up transformer delivers the generation to a voltage level of 69 kV and thus does not meet the criteria in inclusion I2. A second transformer in this example that connects the 69 kV network to the bulk electric system is not solely delivering the generation to the bulk electric system but also delivers power from the bulk electric system to the 69 kV network.

93. Regarding Arizona Public Service's request for clarification, the Commission finds that the voltage connection language in inclusion I2 applies to both the aggregated 75 MVA threshold for a plant/facility and the 20 MVA threshold for individual units.

94. The Commission disagrees with Dominion's contention that inclusion I2 is not needed because the elements identified in inclusion I2 already meet the Registry Criteria. The NERC registration process uses element criteria to identify and register functional entities, not the actual equipment. In contrast, the focus of the bright-line definition is the facilities, not the owners or operators of the facilities. Similarly, with regard to Southern Companies' belief that there are instances where generators may be connected to lower voltages that may fit under inclusion I2 but would not necessarily fit in the Registry Criteria, the Commission agrees that the Registry Criteria allows the Regional Entities and NERC to consider other factors regarding entity registration which may result in cases where the bulk electric system status and registry status differs for certain equipment owners and operators.

95. Regarding ISO New England's assertion that generators that connect to the bulk electric system via transmission facilities with voltages below 100 kV are needed for reliability, the Commission believes these generators can be added to the bulk electric system through the exception process, and if registration is warranted for the owners and operators of these generators, the Registry Criteria provides NERC and the Regional Entities the option of registering "[a]ny generator, regardless of size, that is material to

the reliability of the Bulk Power System.”⁸⁸ Aggregate stability impacts of generation below 100 kV could fall into this category of “material to the reliability of the Bulk Power System.”

96. With respect to the suggestions and requests for clarification submitted by MISO, Barrick, SmartSenseCom and Springfield, commenters may raise these suggestions in NERC’s Phase 2 development effort.

3. Inclusion I3 (Blackstart Resources)

NOPR Proposal

97. NERC included as part of the bulk electric system definition “Blackstart Resources identified in a Transmission Operator’s restoration plan.” In the NOPR, the Commission agreed with NERC that inclusion of blackstart resources in the definition is vital to reliability and is an improvement to the definition. The Commission requested clarification whether the term “restoration plan” refers to the system restoration plans required in the Emergency Preparedness and Operations (EOP) Reliability Standards or included in a Commission approved tariff.⁸⁹ The Commission also expressed concern whether a reliability gap exists with regard to cranking paths. The Commission explained that cranking paths are an important element of system restoration, and questioned

⁸⁸ NERC Statement of Compliance Registry Criteria, section III.c.4.

⁸⁹ NOPR, 139 FERC ¶ 61,247 at P 67. Reliability Standard EOP-005-1, System Restoration Plans, requires a transmission operator to create “a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system.”

“whether reliability can be adequately maintained when blackstart generators are defined as part of the bulk electric system but not the transmission paths that are used to deliver the energy from blackstart generators to the integrated transmission system.”⁹⁰

Accordingly, the Commission requested comment on whether a reliability gap exists and also requested comment on the appropriate role, if any, of state regulators in ensuring that energy from blackstart generation is reliably delivered through cranking paths to restart the system after an event.

Comments

98. NERC confirms that the “restoration plan” in inclusion I3 refers to the restoration plans in the EOP Reliability Standards. Other commenters support NERC’s explanation.⁹¹ With regard to cranking paths, NERC explains that cranking paths above 100 kV are included in the bulk electric system by the core definition. NERC states that some cranking paths identified in a restoration plan “are composed of distribution system elements.”⁹² NERC adds that certain Reliability Standards, such as Reliability Standards CIP-002-4 and EOP-005-2, address reliability of cranking paths without regard to voltage which demonstrates there are other ways to ensure reliable operation of the bulk electric system without including non-bulk electric system cranking paths within the definition.

⁹⁰ NOPR, 139 FERC ¶ 61,247 at P 68.

⁹¹ *E.g.* EEI, APPA, Southern Companies, SoCal Edison, PSEG Companies, and NV Energy.

⁹² NERC Comments at 11.

In contrast, PSEG Companies request that, if the Commission supports NERC's exclusion of cranking paths below 100 kV, the Commission confirm that below 100 kV cranking paths would be excluded from being enforced in Reliability Standards that address cranking paths unless they are added to the bulk electric system by the exception process.⁹³

99. Other commenters agree that no reliability gap exists and that the Commission correctly noted that including cranking paths may improperly bring distribution level elements into the bulk electric system. Southern Companies and others contend that if a cranking path that does not fall within the definition of bulk electric system but is needed for reliability, the exception process would be the place to make that determination.⁹⁴ NESCOE states that cranking paths are generally part of the distribution system and state regulators have the responsibility to ensure the reliability of these lower voltage facilities and are acutely aware of the importance of effective blackstart capability. NESCOE adds that these facilities are needed for restoration not for continuous operation.⁹⁵ ODEC is concerned that including cranking paths will create an incentive for generators not making their units available for blackstart services. Alameda suggests that "any potential gap can be closed by requiring [t]ransmission [o]perators ("TOPs") that identify

⁹³ PSEG Comments at 10.

⁹⁴ Southern Companies Comments at 7. *See also* TAPS Comments at 5.

⁹⁵ NESCOE Comments at 10.

blackstart generation and a related cranking path or paths in their system restoration plans to analyze and enter into an operating agreement with the owner of identified cranking path facilities not owned by the [transmission operator].”⁹⁶

100. While other commenters agree that the term “restoration plan” refers to the EOP Reliability Standards, they assert that cranking paths should be included in the bulk electric system. Idaho Power, ITC Companies and BPA assert that cranking paths are crucial to system restoration and implicate reliability even if they are local distribution or below 100 kV facilities.⁹⁷ ITC Companies state that not including cranking paths will cause regional differences and inconsistent application resulting in some owners electing to exclude such assets. Without cranking paths included in the definition, ITC Companies state that they will be “required to ensure its blackstart plan does not include blackstart generators connected to transmission facilities at voltages below 100 kV since [they] could not be assured that the proper standards are being followed for these blackstart cranking paths.”⁹⁸

101. MISO recommends that the Commission clarify that the term “restoration plan” refers to the EOP Reliability Standards but not include all blackstart resources in a Commission-approved tariff. MISO is concerned that including blackstart resources

⁹⁶ Alameda Comments at 6.

⁹⁷ Idaho Power Comments at 4, ITC Companies at 3-4. *See also* BPA Comments at 3-4.

⁹⁸ ITC Comments at 5.

from sources other than the EOP Reliability Standards is not necessary for reliability and could encourage generators to remove blackstart resources in order to avoid being subject to “unduly complex requirements.”⁹⁹

Commission Determination

102. We find that NERC’s inclusion of blackstart resources in the definition is an improvement to the definition. We also agree with NERC’s statement that the “restoration plan” in inclusion I3 refers to the restoration plans in the EOP Reliability Standards. With regard to cranking paths, the Commission declines to include all cranking paths regardless of voltage level. The Commission finds that cranking paths operating at or above 100 kV are included in the bulk electric system by the core definition, and if a cranking path that does not fall within the definition of bulk electric system, (i.e. operating at or above 100 kV) but is needed for reliability, such elements can be included in the bulk electric system through the exception process. We also disagree that not including cranking paths will cause regional differences and inconsistent application resulting in some owners electing to exclude such assets. The revised definition includes all Transmission Elements at or above 100 kV. Thus, to the extent a cranking path is operating at or above 100 kV and a “Transmission Element,” it would be included in the bulk electric system. If a cranking path is below 100 kV and is necessary for operation of the interconnected transmission network or operates at or above 100 kV

⁹⁹ MISO Comments at 6.

and is not necessary for the operation of the interconnected transmission network, the status of the cranking path may be determined in the exception process. These steps will ensure consistent treatment across the regions. In response to ITC Companies' concern that, without cranking paths included in the definition it will be required to ensure its blackstart plan does not include blackstart generators connected to transmission facilities at voltages below 100 kV, we note that such elements can be considered for inclusion through the exception process. Similarly, with regard to NESCOE's statement that lower voltage cranking paths are generally part of the distribution system, we note that facilities operating below 100 kV would be excluded as part of applying of the core definition. In addition, as we discuss above, in certain instances the Commission will make determinations as to which facilities are used in local distribution and thus should be excluded from the bulk electric system.¹⁰⁰

103. With regard to PSEG Companies' request that the Commission confirm that Reliability Standards do not apply to below 100 kV cranking paths unless they are added to the bulk electric system by the exception process, we find that PSEG Companies' request is outside the scope of this proceeding but note that Reliability Standard EOP-005-2 addresses cranking paths with no voltage limits.¹⁰¹

¹⁰⁰ See *supra* PP 66-73.

¹⁰¹ Reliability Standard EOP-005-2, Requirement R6 states "[e]ach [t]ransmission [o]perator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum." Requirement R6.1 states that the

(continued...)

4. Inclusion I4 (Dispersed Power Producing Resources)

NOPR Proposal

104. NERC asserts inclusion I4, dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating), is needed “to accommodate the effects of variable generation” on the bulk electric system.¹⁰² NERC further stated that even though inclusion I4 could be considered subsumed in inclusion I2 (generating resources), NERC believes it is appropriate “to expressly cover dispersed power producing resources utilizing a system designed primarily for aggregating capacity.”¹⁰³

105. In the NOPR the Commission stated that inclusion I4 provides “useful granularity” in the bulk electric system definition, but requested comment whether inclusion I4 includes “the individual elements (from each energy-producing resource at the site through the collector system to the common point at a voltage of 100 kV or above) used to aggregate the capacity and any step-up transformers used to connect the system to a common point at a voltage of 100 kV or above.”¹⁰⁴

transmission operator shall verify “[t]he capability of [b]lackstart [r]esources to meet the [r]eal and [r]eactive [p]ower requirements of the [c]ranking [p]aths and the dynamic capability to supply initial [l]oads.”

¹⁰² NERC BES Petition at 18.

¹⁰³ *Id.*

¹⁰⁴ NOPR, 139 FERC ¶ 61,247 at P 71.

Comments

106. NERC states that the inclusion is meant to address the dispersed power producing resources themselves, not the individual elements of the collector systems operated below 100 kV. With regard to energy delivery elements in collector systems and interconnection facilities, NERC states these items were specifically not included in inclusion I4. According to NERC, this decision was intended to avoid categorically including as part of the bulk electric system assets that may include local distribution facilities. EEI believes that inclusion I4 applies to generating resources meeting the threshold in the aggregate, not the individual generating units. EEI agrees with NERC that the inclusion does not include individual elements of the collector systems operated below 100 kV. LPPC believes that generating units aggregating to 75 MVA are often very small and non-dispatchable, and the reliability implications of these units will be negligible but the compliance burden would be quite high.

107. Several commenters urge the Commission to not interpret inclusion I4 as including wind turbines and electrical collector systems within a wind plant and only include the electrical equipment at the point of interconnection with the bulk electric system.¹⁰⁵ AWEA believes that including all this equipment will potentially burden the owners with NERC compliance processes that were intended for large scale generators. AWEA argues that the “main transformer’s high-side terminal and the generator lead/tie

¹⁰⁵ See, e.g., AWEA, Southern Companies, Consumer Energy, BPA. Hydro One, G&T Cooperatives, and ISO New England.

line” should also be excluded unless another generator connects to the initial generator’s facilities.¹⁰⁶ AWEA asserts that no one has demonstrated that there is any material reliability benefit from including resources envisioned by inclusion I4. AWEA and others state that if the Commission believes such resources should be included, such inclusion should be done on a case-by-case basis rather than generically.¹⁰⁷

108. Along the same lines, NESCOE believes that, absent a reliability risk a generic inclusion could adversely impact state policies to encourage renewable generation development by imposing additional costs. NESCOE states that setting the line for inclusion at 75 MVA is not supported by technical analysis since intermittent sources of power deliver only a fraction of their nameplate rating. NESCOE believes 300 MVA is a better threshold.

109. ISO New England contends that the term “common point” is unclear and notes that the inclusion could be interpreted to mean that if the individual generating units are “all collected at 34.5 kV, the ‘common point’ is at 34.5 kV and the entire group of resources should be found to be [not part of the bulk electric system].”¹⁰⁸

ISO New England believes this is not an appropriate interpretation because it would defeat the intent of the inclusion which is to classify large aggregated generating stations

¹⁰⁶ AWEA Comments at 2.

¹⁰⁷ *E.g.*, Idaho Power.

¹⁰⁸ ISO New England Comments at 7.

as part of the bulk electric system. Similarly, Springfield questions the meaning of “collector system” and proposes language to define it.¹⁰⁹

110. SmartSenseCom states that facilities over a certain significant nameplate rating that are stepped up to over 100 kV should be subject to Reliability Standards in light of their potential impact to system reliability. SmartSenseCom suggests that the Commission direct NERC to modify inclusions I2 and I4 in order to ensure that generating units that are stepped up to 100 kV or above by the use of a transformer with a low side of less than 100 kV (or multiple contiguous transformers of less than 100 kV on the low side) are also included within this definition.¹¹⁰

111. MISO recommends that the Commission withdraw its proposal to approve inclusion I4. MISO believes inclusion I4 is unnecessary given the criteria in inclusion I2. MISO states that elements meeting the criteria in inclusion I2 would be considered part of the bulk electric system, irrespective of whether it is considered a dispersed power producing resource. MISO adds that a specific inclusion for dispersed power producing resources could subject the collector systems to unnecessary monitoring by the reliability coordinator or other registered entities as collector systems at dispersed power producing facilities generally do not affect the reliability of the bulk electric system.

¹⁰⁹ Springfield proposes to add the following sentence at the end of inclusion I4: “For purposes of this inclusion, a Collector System is any infrastructure not connected to load – where parasitic load associated with a generation unit or units is not considered load.”

¹¹⁰ SmartSenseCom Comments at 12.

Commission Determination

112. The Commission finds that inclusion I4 provides useful granularity in the bulk electric system definition. The clarifying language in inclusion I4 regarding the collector system language is consistent with language in the Registry Criteria, section III.c.2. The Commission agrees that it is appropriate “to expressly cover dispersed power producing resources utilizing a system designed primarily for aggregating capacity.”¹¹¹

113. As the Commission previously stated in the inclusion I2 discussion, multiple step-up transformers that are solely used to deliver the generation to the bulk electric system at 100 kV or above qualify the generator or plant/facility and the step-up transformers for inclusion in the bulk electric system.

114. Similarly, the collector system in inclusion I4, described by NERC and others as being designed for aggregating capacity and solely used to deliver the aggregated capacity to the bulk electric system at 100 kV and above, falls into the category of multiple step-up transformers through the high side of the main transformer that connects to 100 kV or above. NERC reasons that proposed inclusion I4 was intended to avoid categorically including assets that may include local distribution facilities. While we believe most collector systems operate below 100 kV, the Commission disagrees that collector systems described in inclusion I4 that solely deliver aggregated generation to the bulk electric system contain local distribution facilities because power is delivered

¹¹¹ NERC BES Petition at 18.

from the collector system to the bulk electric system. However, the Commission will not direct NERC to categorically include collector systems pursuant to inclusion I4.

115. We disagree with AWEA and other commenters that contend that inclusion I4 should be interpreted to not include the dispersed power producing resources within a wind plant in the bulk electric system. We agree with NERC's statement that the purpose of this inclusion is to include such variable generation (e.g., wind and solar resources). NERC noted that, while such generation could be considered subsumed in inclusion I2 (because the gross aggregate nameplate rating of the power producing resources must be greater than 75 MVA), NERC considered it appropriate for clarity to add this separately-stated inclusion to expressly cover dispersed power producing resources using a system designed primarily for aggregating capacity. In addition, although dispersed power producing resources (wind, solar, etc.) are typically variable suppliers of electrical generation to the interconnected transmission network, there are geographical areas that depend on these types of generation resources for the reliable operation of the interconnected transmission network. The Commission believes that owners and operators of these resources that meet the 75 MVA gross aggregate nameplate rating threshold are, in some cases, already registered and have compliance responsibilities as generator owners and generator operators. Regarding AWEA's request that a transformer's high-side terminal and the generator lead line should also be excluded, such determinations may be made on a case-by-case basis in the exception process. With regard to commenters who believe that dispersed power producing resources should be included on a case-by-case basis rather than generically, this would be inconsistent with

the bright-line concept that NERC developed to have consistent application of the definition across the country. If such generating resources are included through inclusion I4, they are eligible for exclusion through use of the exception process. With respect to the concern raised by ISO New England regarding the term “common point,” ISO New England may raise this concern in NERC’s Phase 2 development effort.

5. **Inclusion I5 (Static or Dynamic Reactive Power Devices)**

NOPR Proposal

116. Inclusion I5 identifies as part of the bulk electric system “[s]tatic or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.” In its petition, NERC explained that this inclusion is the technical equivalent of inclusion I2 (generating resources), for reactive power devices and points out that the existing definition is unclear as to how these devices are treated.¹¹² NERC stated inclusion I5 provides clarity by “providing specific criteria for Reactive Power devices, thereby further limiting subjectivity and the potential for discretion” in the application of the revised definition.¹¹³

¹¹² NERC BES Petition at 18.

¹¹³ *Id.*

117. In the NOPR, the Commission agreed with NERC that inclusion I5 adds clarity to the application of the bulk electric system definition by providing specific criteria for reactive power devices. For cases where the reactive power device is connected through a transformer designated in inclusion I1, the Commission requested comment whether both the reactive power device and the transmission elements connecting the reactive power device to the transformer are included as part of the bulk electric system pursuant to inclusion I5.¹¹⁴

Comments

118. NERC and other commenters note that inclusion I5 is intended to include the reactive resource itself and the other portions of the definition are intended to designate whether the remaining electrical components are part of the bulk electric system.¹¹⁵

NERC, EEI, National Grid, Utility Services and G&T Cooperatives refer to inclusion I1 as the proper place to determine whether transformers connected to reactive devices are included as part of the bulk electric system.

119. BPA and WPPC support excluding both the reactive device and the transformer from the bulk electric system if the device supports local distribution. Conversely, if the facilities provide reactive and voltage support to the bulk electric system, the reactive

¹¹⁴ NOPR, 139 FERC ¶ 61,247 at P 73.

¹¹⁵ *E.g.*, EEI.

device and associated equipment, such as the transformer, should be classified as a bulk electric system facility.

120. AEP considers the transmission elements connecting the reactive power device to the transformer to be included in the bulk electric system definition and should be deemed part of inclusion I5.¹¹⁶ Idaho Power contends that both the reactive device and the transformer should be included in the bulk electric system. Idaho Power states that if the transformer is included as part of inclusion I1, then it should be included.¹¹⁷

121. PSEG Companies view the issue as one of “bulk electric system contiguity” and therefore should be addressed during Phase 2. MISO recommends that the Commission require NERC to include a size threshold or an impact test. According to MISO, this will avoid creating incentives to owners of small reactive devices to disconnect them to avoid being classified as transmission owners or operators. With regard to transformers, MISO states that both the reactive power device and the transmission elements are included, but because these facilities have a generally localized impact on reliability, MISO recommends that the Commission clarify that they are not transmission equipment that subjects their owners and operators to the requirements applicable to registered transmission operators under the NERC Reliability Standards.

¹¹⁶ AEP Comments at 4.

¹¹⁷ Idaho Power Comments at 5.

122. G&T Cooperatives suggest two clarifications. First, inclusion I5 should not apply to reactive power devices that are connected to the bulk electric system by a radial line excluded by exclusion E1 or a local network excluded by exclusion E3. G&T Cooperatives view this exclusion as implicit in inclusion I5, which references devices “connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in [i]nclusion I1.” Second, G&T Cooperatives believe that inclusion I5 should be clarified to include a minimum size threshold similar to the size threshold for generating resources under Inclusion I2. According to G&T Cooperatives because inclusion I2 does not apply to all generating resources and inclusion I5 is the “technical equivalent” of inclusion I2, a size threshold comparable to that found in inclusion I2 is implicit for reactive power devices.

Commission Determination

123. The Commission approves inclusion I5 and finds that the inclusion adds clarity to the application of the bulk electric system definition by providing specific criteria for reactive power devices. The Commission also accepts NERC’s response for cases where the reactive power device is connected through a transformer designated in inclusion I1 – that the reactive resource itself is included in the bulk electric system pursuant to inclusion I5 and the transmission elements connecting the reactive power device to the transformer are addressed in other portions of the definition. The Commission notes that this interpretation is different from inclusion I2 because inclusion I2 specifies including the equipment (step-up transformers) that connects generators to the bulk electric system. Nonetheless inclusion I5 provides criteria for reactive power devices that are not

explicitly addressed in the existing definition. The Commission does not agree with G&T Cooperatives that exclusions E1 and E3 override inclusion I5 and exclude the reactive power devices. Exclusions E1 and E3 exclude transmission elements only and not resources.

124. The Commission agrees with PSEG Companies that issues, such as whether the connecting equipment for reactive devices should be included pursuant to inclusion I5, can be raised in Phase 2. Similarly, the issues raised by AEP, Idaho Power, MISO and G&T Cooperatives may be raised in NERC's Phase 2 effort.

Exclusions

125. The proposed definition identifies four facilities configurations that should not be included in the bulk electric system: (1) radial systems; (2) behind-the-meter generating units; (3) local networks; and (4) retail customer reactive power devices.

126. We agree that the proposed exclusions provide clarity and granularity. For example, the exclusion of generating units on the customer's side of the retail meter that serves all or part of the retail load (exclusion E2) and the exclusion for reactive power devices owned and operated by a retail customer for its own use (exclusion E4) provide reasonable limitations on bulk electric system elements. While we approve in the Final Rule the language of exclusions E1, E2 and E4, we have concerns with regard to the application of exclusions E1 and E3 in specific situations and, thus, direct NERC to implement or apply these exclusions consistent with the determinations set forth below. In addition, we direct NERC to remove the 100 kV minimum operating threshold language from exclusion E3.

6. Exclusion E1 (Radial Systems)

127. Exclusion E1 provides as follows:

Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

- a) Only serves Load. Or,
- b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
- c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

In its petition, NERC explained that radial facilities are excluded under the currently effective bulk electric system definition, and the detailed criteria in the revised definition provide enhanced clarity.¹¹⁸

Commission Determination

128. The Commission approves exclusion E1. We agree with NERC that the currently-effective definition of bulk electric system excludes radial facilities, and the modifications provide additional granularity regarding the radial exclusion. In the NOPR, the Commission requested comment regarding specific applications of the E1 radial system exclusion. Below, we discuss these applications and comments received, and provide further explanation or direction as we deem appropriate.

¹¹⁸ NERC BES Petition at 18.

a. **Exclusion E1 Does Not Apply to Whether Generation is Included or Excluded**

NOPR Proposal

129. In the NOPR, the Commission requested comment on whether exclusion E1 removes from the bulk electric system “generation connected to a radial system that otherwise satisfies inclusion I2.”¹¹⁹ The Commission sought to ensure that the conditions in exclusion E1 would not “lead to conflicting results when applying inclusion I2 and exclusion E1.”¹²⁰ The Commission noted that exclusion E1 applies to “a group of contiguous *transmission* Elements that emanates from a single point of connection of 100 kV or higher....”¹²¹ The Commission observed that the term “Elements” includes the term generator, and that the use of the term “transmission” before “Elements” indicates that exclusion E1 applies only to transmission elements.¹²² Thus, the Commission stated that “transmission Elements” do not include generating resources that are bulk electric

¹¹⁹ NOPR, 139 FERC ¶ 61,247 at P 76.

¹²⁰ *Id.*

¹²¹ NOPR, 139 FERC ¶ 61,247 at P 77.

¹²² “Element” is defined in the NERC Glossary as “[a]ny electrical device with terminals that may be connected to other electrical devices *such as a generator, transformer, circuit breaker, bus section, or transmission line*. An element may be comprised of one or more components.” (emphasis added).

system resources pursuant to the generating resources included in inclusion I2 connected to a radial line operated at 100 kV above.¹²³

Comments

130. NERC confirms that exclusion E1 does not apply to nor is it determinative of whether any generation is included or excluded from the bulk electric system. NERC states that, whether or not generation is included in the bulk electric system is determined by inclusions I2 through I4 and exclusion E2. Other commenters, including EEI, SoCal Edison, TAPS, Hydro One, and Alameda, also state that exclusion E1 does not apply to generating resources. Southern Companies suggest that the use of the term “includes” in subparts (b) and (c) could lead to some ambiguity because the implication is that a radial system includes generating resources. Southern Companies suggests that, the word “serves” should replace the word “include” to better reflect the intent of the provision.

131. PSEG Companies state there is confusion created by the fact that generators included in one provision of the definition (inclusion I2) are excluded under others (exclusions E1 through E3). According to PSEG Companies, a generator cannot be included under one provision of the bulk electric system definition and excluded under

¹²³ See NOPR, 139 FERC ¶ 61,247 at P 77 and n.100 (citing NERC BES Petition, Exh. D, Consideration of Comments Report, at 223 (“Exclusion E1 is an exclusion for the contiguous transmission Elements connected at or above 100 kV.”)).

another provision and that this issue requires clarification and, once clarified, the bulk electric system definition needs to be modified accordingly.¹²⁴

132. SmartSenseCom states that in the event of a conflict between an inclusion and exclusion, “there should exist a presumption that the [e]lement be considered included, absent an [e]xception” and asks that the Commission direct NERC to include a provision that states this presumption.¹²⁵

Commission Determination

133. The Commission finds that the radial system exclusion only applies to “transmission Elements” and does not apply to nor is it determinative of whether any generation is included or excluded from the bulk electric system. This understanding is consistent with NERC’s defined terms, and consistent with the comment of NERC and other commenters. Further, in response to Southern Companies, AEP and PSEG Companies, we believe that the language of exclusion E1 is sufficiently clear that it does not exclude generation facilities that are otherwise included as part of the bulk electric system pursuant to inclusion I2. Thus, we will not direct NERC to modify exclusion E1 to state this more explicitly. We agree with SmartSenseCom that exclusion E1 should not lead to conflicting results when applying inclusion I2, but we decline to direct NERC to include a provision that specifically states this presumption.

¹²⁴ PSEG Comments at 11-13.

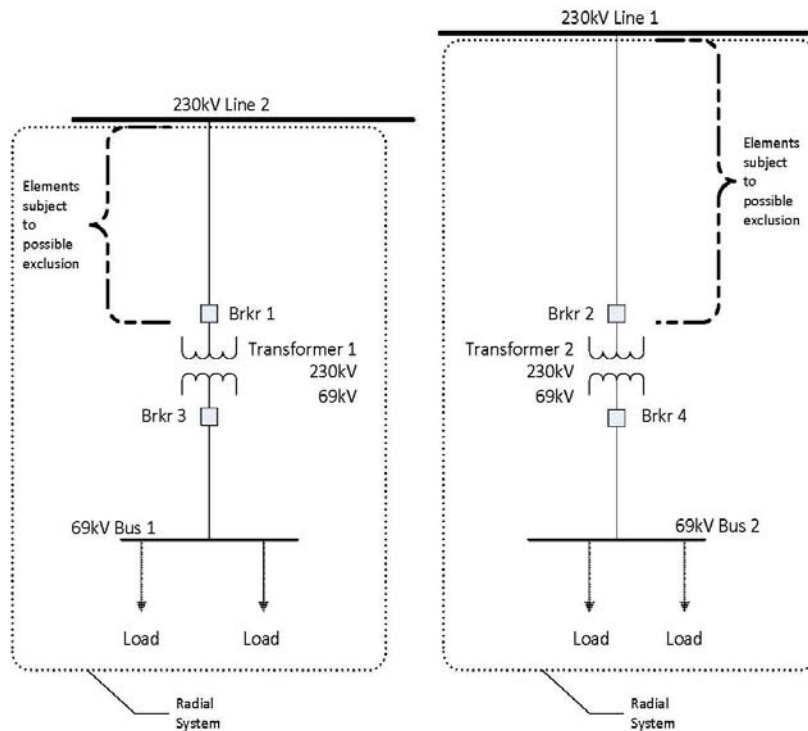
¹²⁵ SmartSenseCom Comments at 13.

b. Definition of “Radial Systems,” Figure 1 and Condition (a) Radials Only Serving Load

NOPR Proposal

134. Exclusion E1 defines the term “radial systems” as “a group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher.” In the NOPR, the Commission requested comment on how NERC’s proposal would be applied in the three scenarios. Figure 1 in the NOPR depicted facilities configurations in which all of the 230 kV and 69 kV transmission elements emanate from a single point of connection of 100 kV or higher. The Commission requested comment on whether each of the radial systems shown in figure 1, the 230 kV elements above each transformer to the point of connection to each 230 kV line, respectively, are excluded from the bulk electric system pursuant to exclusion E1.

Figure 1
Two Radial Systems Eligible for Exclusion E1



Comments

135. NERC and other commenters state that both radial systems depicted in figure 1 would be subject to exclusion E1(a) because they each only serve load.¹²⁶ ELCON agrees with NERC adding that these types of radial systems pose no reliability risk to the interconnected transmission network if the system is lost due to a fault condition. Similarly, SoCal Edison states that the figure 1 facilities would either be excluded or not

¹²⁶ *E.g.*, Southern Companies, AEP, National Grid, TAPS, ISO New England, Barrick, IUU, and WPPC.

part of the bulk electric system. SoCal Edison asserts that, because transformers 1 and 2 each have secondary voltages that are less than 100 kV, they do not meet the inclusion I1 requirements and, thus, are not included in the bulk electric system. In other words, SoCal Edison believes exclusion E1 should exclude all radial facilities that are greater than 100 kV up to the point where “the system is no longer radial, as indicated in figure 1 by the brackets where the 230 kV lines meet [lines 1 and 2].”¹²⁷ APPA believes that all the scenarios described by the Commission could create reliability concerns “if taken in isolation and operated in a certain matter” and believes that the exception process can capture configurations that pose a significant risk to the reliable operation of the interconnected transmission network. Idaho Power maintains that it is inappropriate to apply exclusion E1 for 230 kV elements in the scenarios if the breakers are part of the protection scheme for a three terminal 230 kV line. Idaho Power adds that if either breaker only opens for transformer protection, the exclusion would be applicable.

136. Anaheim agrees that the radials shown in figure 1 should be excluded and requests clarification that the associated bus work and protection system equipment installed on those radial lines are also excluded. Anaheim advocates that the exclusion should also apply to protection system equipment on the excluded facilities that provide backup protection for devices that are part of the bulk electric system, i.e. lines 1 and 2 in figure 1.

¹²⁷ SoCal Edison Comments at 5.

137. BPA is concerned about excluding the 230 kV lines without review by a planning authority or transmission operator because the fault magnitude on voltages above 200 kV are much higher than below 200 kV lines. BPA states that since actual power flows on systems above 200 kV are much higher, these systems have a higher risk for serious impacts on the interconnected transmission system.

138. Holland supports the exclusion of radial systems but contends that the phrase “emanates from a single point of connection” could be too narrowly interpreted. According to Holland, multiple buses within a single substation could be viewed as multiple points of connections. Holland believes that an entity whose connection emanates from a single substation should not be denied an exclusion solely because it connects to multiple buses at the single substation.

139. Consumers argues that the exclusion of 100 kV radial systems that only serve load exceeds the Commission’s jurisdiction and the Seven Factor Test.¹²⁸ Consumers believes that exclusion E1(a) would exclude radials that only serve load and this phrase expands the Commission’s jurisdiction by classifying 100 kV distribution systems that primarily serve load but could also have a secondary purpose. Consumers also argues that this exclusion is inconsistent with the Seven Factor Test which examines whether local distribution facilities are “primarily” radial in character. Further, Consumers argues that

¹²⁸ Consumers cites to *Detroit Edison Co. v. FERC*, 334 F.3d 48 (D.C. Cir 2003) as support for its belief that the Commission cannot rewrite the FPA to exclude only facilities used exclusively in local distribution. See Consumers comments at 7.

the Commission should not adopt a rule that exceeds its jurisdiction or constitutes a collateral attack on the local distribution findings of the Seven Factor Test.

Commission Determination

140. The Commission agrees with NERC that the radial systems shown in figure 1 meet the definition of “radial system” in exclusion E1. This configuration would result in the 230 kV lines between transformers 1 and 2 to the two 230 kV lines, respectfully, being excluded from the bulk electric system. The Commission agrees with NERC and other commenters that both radial systems depicted in figure 1 would be subject to exclusion E1 condition (a) because they each only serve load.

141. Idaho Power, BPA and Anaheim raise concerns about protection system equipment and design, needed for analysis by the planning authority and transmission operator, while APPA states that all scenarios described by the Commission could create reliability concerns. Regarding these concerns, the Commission agrees with APPA that the exception process can be used to add to the bulk electric system specific configurations that pose a significant risk to the operation of the interconnected transmission network.

142. The Commission disagrees with Holland’s interpretation that the phrase “emanates from a single point of connection” can refer to multiple buses. The phrase refers to a single point, and if there is more than one point of connection the configuration does not meet the radial system definition as stated in exclusion E1. NERC, in the standard development process, emphasized that radial systems cannot have multiple connections at

100 kV or higher. Networks that have multiple connections at 100 kV or higher may qualify under exclusion E3.¹²⁹

143. The Commission also disagrees with Consumers that the exclusion of 100 kV radial systems that only serve load expands the Commission's jurisdiction by classifying 100 kV distribution systems that primarily serve load, but may also have a secondary purpose, as transmission. First, exclusion E1 condition (a) reflects the language contained in the current bulk electric system definition and therefore, is itself not an expansion from the existing definition. In addition, as NERC stated, application of the definition is a three-step process. In step 1, the core definition is used to establish the bright line of 100 kV, the overall demarcation point between bulk electric system and non-bulk electric system elements. Step 2, applying the specific inclusions, provides additional clarification for the purposes of identifying specific elements that are included in the bulk electric system. Step 3 is to evaluate specific situations for potential exclusion from the bulk electric system. Further, an entity may seek a case-specific exception if it believes that facilities with radial qualities that are not excluded pursuant to exclusion E1 or petition the Commission when seeking a determination whether a facility, otherwise included in the bulk electric system, is used in local distribution. Thus, merely applying

¹²⁹ NERC BES Petition, Exhibit E, "Complete Development Record of the Proposed Revised Definition of "Bulk Electric System," Consideration of Comments on Initial Ballot - Definition of BES," at 259.

the definition, and the inclusions or exclusions is not necessarily the end of the inquiry regarding whether an element is part of the bulk electric system.

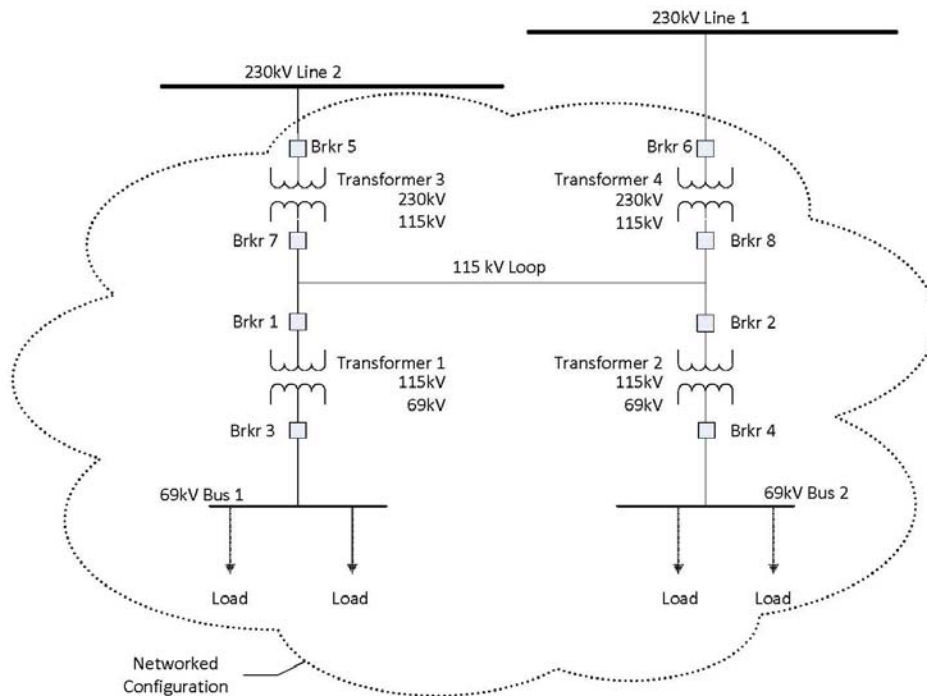
c. **Figure 2 and Condition (a) Radials Serving Only Load**

NOPR Proposal

144. In the NOPR, the Commission requested comment on the scenario shown in figure 2 which shows a 115 kV loop, with the configuration emanating from two points of connection of 100 kV or higher. Specifically, the Commission requested comment on whether “the 115 kV and 230 kV elements above Transformers 1 and 2 to the points of connection to the two 230 kV lines would be excluded from the bulk electric system pursuant to exclusion E1.”¹³⁰ The Commission asked for comment on whether it is more appropriate to analyze figure 2 pursuant to the “local network” exclusion E3 and, if so, what if any elements operated at or above 100 kV would be excluded pursuant to exclusion E3.

¹³⁰ NOPR, 139 FERC ¶ 61,247 at P 80.

Figure 2
Networked Configuration w/115 kV Loop



Comments

145. NERC states that figure 2 is a non-radial loop on the 115 kV system. According to NERC, the 115 kV elements above transformers 1 and 2 to the point of interconnection with lines 1 and 2 would not be eligible for exclusion E1 because they do not emanate from a single point of connection. NERC also states that it would be appropriate to evaluate figure 2 under exclusion E3 as a potential local network.¹³¹ For such a

¹³¹ See also Comments of NESCOE, BPA, Idaho Power, ITC Companies, and National Grid.

candidate local network to qualify for exclusion, NERC states that additional technical analysis is needed to determine if all the exclusion E3 criteria are satisfied.¹³² NERC asserts that without such a technical analysis, the 115 kV elements above transformers 1 and 2 should be considered part of the bulk electric system.

146. Likewise, Idaho Power, ITC Companies, and National Grid contend that the figure 2 configuration should be included in the bulk electric system. Southern Companies believe exclusion E1 may apply from the breakers down and that the configuration may belong to exclusion E3. AEP assumes that each of the facilities below the 115 kV loop shown in figure 2, and including breaker 1 and breaker 2, are radial and excluded pursuant to exclusion E1. According to AEP, the facilities above breakers 1 and 2 may be excluded pursuant to exclusion E3 depending on the circumstances.¹³³

147. Valero states that the figure 2 configuration is very similar to common facilities configurations employed in many industrial facilities involving the interconnection of the industrial facility to the utility through two high voltage feeder lines that originate at different utility owned and operated substations. Valero requests that the Commission include in the final rule an additional exclusion that would “categorically exclude from the [bulk electric system] any on-site high voltage switchyard facilities (less than 300 kV) owned by the industrial end-user where the predominant function of the facilities is to

¹³² *E.g.*, ISO New England Comments at 10, MISO Comments at 7.

¹³³ AEP Comments at 7.

distribute electricity in an inward direction to the end-user's load.”¹³⁴ WPPC argues that figure 2 shows both radial and network systems and that the system from the 115 kV loop upwards would be assessed under exclusion E3 and below that point would be assessed by exclusion E1.

Commission Determination

148. The Commission affirms NERC's statement that figure 2 is a non-radial loop and thus would not be eligible for exclusion E1 because it does not emanate from a single point of connection. The Commission agrees with commenters that the elements below the 115 kV loop should be assessed as two separate radial systems pursuant to exclusion E1. The remaining elements (the 115 kV loop, transformers 3 and 4 and the 230 kV tie lines above the transformers to the two 230 lines 1 and 2) should be assessed pursuant to exclusion E3 and if the configuration meets the criteria of exclusion E3, the elements could be excluded.

149. Regarding Valero's request for an additional exclusion if equipment owners' configurations cannot meet the exclusion E3 criteria, Valero can request that the elements be excluded through the exception process. The exception process allows equipment owners to request an exception regardless of the owner's registration status.

¹³⁴ Valero Comments at 8.

d. **Figure 3 and Condition (a) Radials Only Serving Load**

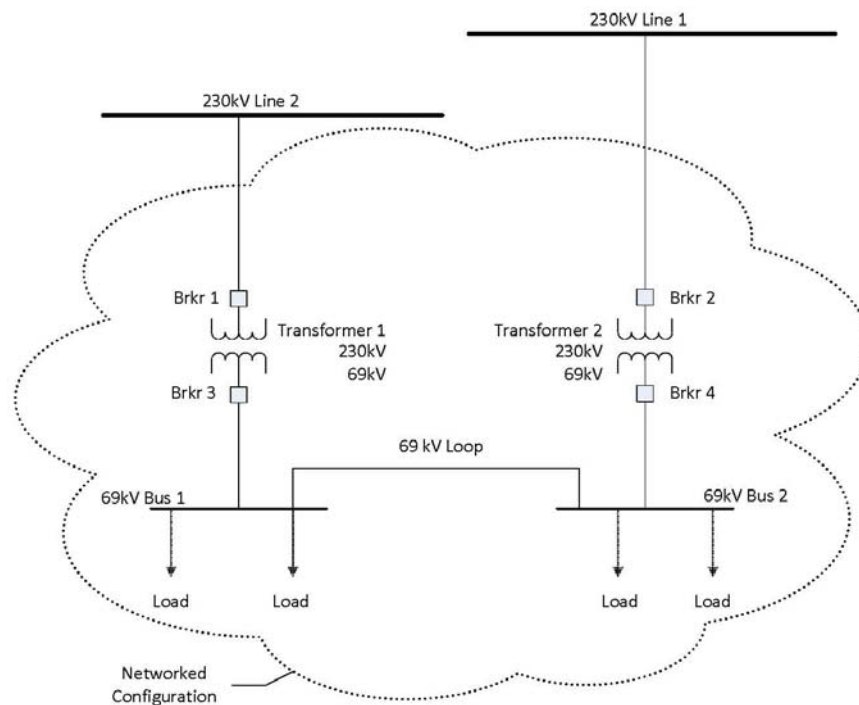
NOPR Proposal

150. In the NOPR, the Commission agreed with NERC's proposal that radial systems only serving load and emanating from a single point of connection of 100 kV or higher should be excluded from the bulk electric system. However, the Commission expressed concern "that the exclusion could allow elements operating at 100 kV or higher in a configuration that emanates from two or more points of connection "to be deemed "radial" even though the configuration remains contiguous through elements that are operated below 100 kV."¹³⁵ Figure 3 in the NOPR illustrated this concern, and the Commission asked for comment on how to evaluate the configuration relative to the radial system definition. The Commission also requested comment on the appropriateness of examining elements below 100 kV to determine if the configuration meets exclusion E1, i.e., whether figure 3 depicts "a system emanating from two points of connection at 230 kV and, therefore, the 230 kV elements above the transformers to the points of connection to the two 230 kV lines would not be eligible for the exclusion E1 notwithstanding the connection below 100 kV."¹³⁶

¹³⁵ NOPR, 139 FERC ¶ 61,247 at P 81.

¹³⁶ *Id.*

Figure 3
Networked Configuration w/69 kV Loop



Comments

151. NERC disagrees with the Commission’s characterization of figure 3 in the NOPR. NERC states that figure 3 does not depict a configuration with two points of 100 kV or higher or a system emanating from two points of connection at 230 kV. According to NERC, except for lines 1 and 2, all the other elements depicted in figure 3 are excluded from the bulk electric system. NERC explains that the elements between line 1 and transformer 2 and from line 2 to transformer 1 are excluded by exclusion E1(a) because “each separate set of [e]lements [described above] is contiguous and emanate from a

single point of connection of 100 kV or higher.”¹³⁷ NERC states that the elements below the 69 kV side of transformers 1 and 2 are excluded from the definition because they are less than 100 kV, and transformers 1 and 2 are excluded because they “bridge voltages of 69 kV and 230 kV” and therefore do not meet inclusion I1.

152. NERC further explains that the focus of the definition of bulk electric system is on looped or networked connections at or above 100 kV. According to NERC, connections operated below 100 kV, generally do not carry significant parallel flow due to the higher impedance of lower voltage facilities. If such facilities are necessary for the reliable operation of the interconnected transmission network, NERC states that the exception process can be used to include such facilities.

153. Exelon agrees with NERC and explains that it has many connections similar to the one shown in figure 3 and provides a specific example where a 138 kV substation is fed by two radially connected 138 kV lines which in turn are connected through 40 MVA transformers to a 12 kV bus section. Exelon states that in its example the 40 MVA transformers cross bus sections so that if one of the 138 kV lines is out of service, each side of the 12 kV bus retains service. Exelon believes that due to the high impedance of the transformers, little energy flows between the buses in Exelon’s example.¹³⁸ Exelon

¹³⁷ NERC Comments at 19.

¹³⁸ Exelon Comments at 6. TAPS states that impedance is inversely proportional to the square of the voltage of the network and power flow is inversely proportional to the impedance. According to TAPS, impedance factors are very significant in limiting the amount of parallel path flows. TAPS Comments at 7.

states that owners and operators of these configurations would be required to go through the exception process.

154. Other commenters believe that the figure 3 configuration may not be eligible for exclusion E1. SoCal Edison explains that the 69 kV loop is not open and therefore is a parallel path to the 230 kV system. BPA, Alameda and WREA do not view the figure 3 system as eligible for exclusion E1 because the system is networked. Idaho Power states that the 230 kV lines would be included only if there is a protection system in place for the 230 kV lines. According to Idaho Power, the elements above the transformers in figure 3 would not be excluded from the bulk electric system. Idaho Power believes this configuration should be evaluated under exclusion E3.

Commission Determination

155. The Commission finds figure 3, which is identical to figure 5, is a networked configuration through a 69 kV loop and does not qualify for exclusion E1. The Commission also finds that, because the load in figure 3 can be served by either 230 kV line, it does not depict a “radial system.” However, the facilities below 100 kV may or may not be necessary for the operation of the interconnected transmission network, and this decision can be made case-by-case in the exception process. In other words, such facilities below 100 kV depicted in figure 3 would be excluded under the general threshold of the core definition unless found on a case-specific basis as necessary for the reliable operation of the interconnected transmission network. Thus, the Commission, while disagreeing with NERC’s interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in

the exception process. Further, as we discuss below in connection with exclusion E3 and figure 5, while we find that the configuration shown in figures 3 and 5 would not be eligible for exclusion E1, we believe that such configurations should be eligible for exclusion E3 for local networks. However, exclusion E3 as written requires the candidate local network to be contiguous and above 100 kV, thus, the exclusion E3 language as written does not allow for figures 3 and 5 to be eligible for the local network exclusion because they are not contiguous *and* include facilities that are not above 100 kV. Therefore, we direct NERC to modify exclusion E3 to remove the 100 kV minimum operating voltage in the local network definition. This modification will enable configurations similar to figures 3 and 5 to be assessed for the local network exclusion. The Commission believes this modification, together with satisfying the criteria outlined in exclusion E3, will appropriately exclude local network configurations that are not necessary to the reliable operation of the interconnected transmission network.¹³⁹

¹³⁹ NERC and Exelon contend that looped or networked connections operating below 100 kV generally do not carry significant parallel flow because of higher impedance characteristics and thus need not be evaluated as part of a radial system. However, the Commission believes that excluding these configurations solely on the level of impedance does not consider other factors, including voltage, the system configuration, type of conductors, length of conductors, and proximity of the networked system in the interconnected transmission network. Regardless of our disagreement with NERC and Exelon regarding the consideration of impedance, however, as we discuss above, configurations such as those described by Exelon may be assessed for exclusion through exclusion E3, which apply criteria to determine whether such facilities are necessary for reliable operation of the interconnected transmission network.

(continued...)

e. **Condition (b) – Radials With Limited Generation and Condition (c) – Radials With Limited Generation and Load**

NOPR Proposal

156. Exclusion E1, condition (b) describes generation connected to a radial system with no load, and condition (c) describes generation connected to a radial system with generation and load. In its petition, NERC stated that conditions (b) and (c) are “intended to address the circumstances of small utilities (including municipal utilities and cooperatives).”¹⁴⁰

157. In the NOPR, the Commission requested comment regarding the specific circumstances that conditions (b) and (c) are intended to address. In addition, the Commission observed that the power generated on these radial systems would be “delivered or injected to the bulk electric system and transported to other markets.”¹⁴¹

The Commission noted that it appeared that a line 100 kV or above connected to a generator with a capacity 75 MVA or below would not be included in the bulk electric system. The Commission requested comment on the appropriateness of excluding such radial facilities.

Accordingly, the inclusion or exclusion of such facilities is better determined through application of exclusion E3, or case-by-case in the exception process.

¹⁴⁰ NERC BES Petition at 19.

¹⁴¹ NOPR, 139 FERC ¶ 61,247 at P 83.

Comments

158. With respect to applicability to small utilities, NERC states that exclusion E1, conditions (b) and (c) are not intended solely for such entities. According to NERC, these conditions are intended to exclude radial systems that have limited benefit to the reliability of the interconnected transmission network. NERC states that the configurations described in exclusion E1(b) and (c) “pose no reliability risk to the interconnected transmission network when the radial system is lost due to a failure or fault condition.”¹⁴²

159. NERC states that the basis for exclusion E1(b) “is dependent on a single point of failure causing the radial system to separate” from the bulk electric system, which will result in a limited loss of generation without an adverse reliability impact to the interconnected transmission network.”¹⁴³ NERC explains that exclusion E1(c) addresses the installation of limited amounts of generation that are installed within a radial system and are intended to serve local load within that radial system.

160. In response to the Commission’s question about the delivery or injection of power from the radial systems described in these exclusions, NERC states that because of the limitation of the generation in exclusion E1(b) and (c), the power generated on the radial system would be delivered to the embedded load within the radial system and injected

¹⁴² NERC Comments at 20.

¹⁴³ NERC Comments at 20.

into the bulk electric system in very limited quantities. NERC argues that subjecting the elements associated with this type of radial system to all the Reliability Standards has limited benefit to the reliability of the interconnected transmission network. NERC believes it is more appropriate to identify these elements through the “the applicability in specific standards where a reliability benefit can be identified.”¹⁴⁴

161. A number of commenters agree with NERC.¹⁴⁵ Idaho Power states that the exclusion is appropriate if the generation connected to the radials is not relied on to meet reliability performance criteria on bulk electric system elements. Idaho Power indicates that it follows the WECC guidelines and thresholds (10 MVA individually, 20 MVA aggregate) to determine the appropriateness of excluding the power from components from radial connected generation. Alameda contends that the radial systems in these exclusions have only a minor impact on the bulk electric system and that system planning and operation assessments must provide for reliable operation under N-1 contingency operations including loss of the exclusion E1(b) and (c) configurations. WPPC states that the generator thresholds in these conditions are a logical cut-off to separate radial systems with generation that is not likely to be meaningful to operation of the bulk electric system.

¹⁴⁴ NERC Comments at 21-22.

¹⁴⁵ *E.g.* Idaho Power, National Grid, AEP, Hydro One, ISO New England, and BPA.

162. Anaheim urges the Commission to clarify that the presence of generation resources connected at voltages below 100 kV “does not invalidate the availability of the radial exclusion for lines that are operated at greater than 100 kV unless the generating unit is actually connected to the higher voltage line.”¹⁴⁶ PSEG Companies state there is confusion regarding the generation limits in exclusion E1(b) and (c) and in exclusion E3. They contend that it is not clear if the generation limit only applies to generators connected at 100 kV or higher. PSEG Companies also ask for clarification regarding the definition of the phrase “non-retail generation.”¹⁴⁷

163. AEP does not believe that the three conditions of exclusion E1 would remove the generation connected to the radial system from the bulk electric system definition but states that the conditions may have the consequence of removing the radial line itself from the definition in error. According to AEP, this would be in cases of a 25 MVA generator (meeting I2 properties) but less than 75 MVA aggregate. AEP suggests that the conditions in (b) and (c) be revised to reference non-bulk electric system generation.¹⁴⁸

Commission Determination

164. We approve exclusion E1 conditions (b) and (c). However, we direct NERC to implement exclusion E1 so that the exclusions for radial systems do not apply to

¹⁴⁶ Anaheim Comments at 7.

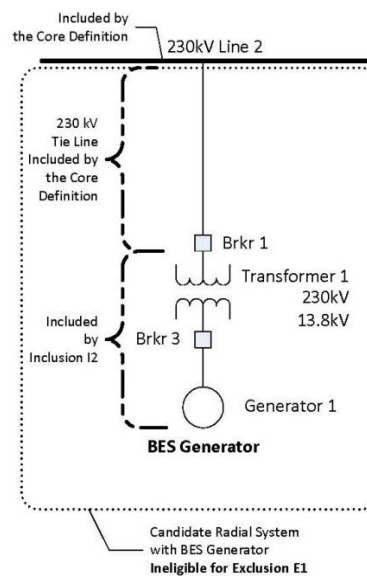
¹⁴⁷ PSEG Comments at 3.

¹⁴⁸ AEP Comments at 5.

tie-lines for bulk electric system generators identified in inclusion I2. If the generator is necessary for the operation of the interconnected transmission network, the Commission believes that it is generally appropriate to have the radial tie-line operating at or above 100 kV that delivers the generation to the bulk electric system included as well.

165. In general, we believe that it is appropriate to have the bulk electric system contiguous, without facilities or elements “stranded” or “cut-off” from the remainder of the bulk electric system as shown in the figure below. However, the contiguous quality of the bulk electric system is lost in exclusion E1, condition (b), because it removes from the bulk electric system the 100 kV or greater generator tie-line that connects the bulk electric system generator to the interconnected transmission network. Such tie-lines should be subject to appropriate Reliability Standards.

Radial System with BES Generation



166. NERC explains that the exclusion of radial systems pursuant to conditions (b) and (c) is based on the premise that a single point of failure causing the radial system to separate from the bulk electric system, resulting in the loss of a limited amount of generation will not have an adverse reliability impact. However, there are other reliability concerns that NERC does not address. For example, both the radial line emanating from a generator and the portion of the bulk electric system to which it is connected have protective relays that require coordination to prevent the lines from tripping. The generator needs to coordinate the protective relays with transmission operators, otherwise there may not be adequate information to prevent a fault on the radial line from causing cascading outages on the bulk electric system. The Commission also notes that the phrase “adverse reliability impact,” which is defined in the NERC Glossary of Terms as “the impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection,” is an extreme result that should not occur from the loss of a single tie-line for any sized generator.¹⁴⁹ A single contingency that results in an “adverse reliability impact” violates planning and operating criteria in Commission approved Reliability Standards.¹⁵⁰ NERC also does not consider issues,

¹⁴⁹ See the NERC Glossary of Terms at http://www.nerc.com/files/Glossary_of_Terms.pdf

¹⁵⁰ See, e.g., Reliability Standards, TPL-002-0b and IRO-004-2.

such as the issue raised by Idaho Power, that the exclusion is appropriate if the generation connected to the radial system is not relied on to meet reliability performance criteria.

167. Some commenters suggest there is a conflict between the inclusion I2 and exclusion E1 because they believe that the 100 kV or greater tie-line and the generator should remain in the bulk electric system. We agree that exclusion E1 as written does not prevent the radial tie-line operating at or above 100 kV from the high side of the step-up transformer to the bulk electric system from being excluded while the generator and associated step-up transformer(s) remain included. Inclusion I2 depends on the status of the tie-line based on the core definition's 100 kV threshold to determine if a generator and its step-up transformers are part of the bulk electric system. Thus, this inclusion results in most bulk electric system generators having a contiguous connection to the interconnected transmission network. As noted above, we believe that it is generally appropriate to have the bulk electric system contiguous. Therefore, the Commission directs NERC to implement exclusion E1 so that the exclusion for radial systems does not apply to tie-lines for bulk electric system generators identified in inclusion I2. This directive provides consistent application of the entire definition by not allowing exclusion E1 to override the qualifying tie-lines pursuant to inclusion I2.

168. The Commission also rejects NERC's argument that subjecting the elements associated with this type of radial system to all the Reliability Standards has a limited benefit to the reliability of the interconnected transmission network. In cases of radial tie-lines for bulk electric system generators where the generator owner also owns the tie-line, NERC has exercised discretion, on a case-by-case basis, in determining which

entities require registration as transmission owners/operators and identified sub-sets of applicable reliability standard requirements for these entities.¹⁵¹ In other situations, such generator tie-lines may appropriately be considered an extension of the generation facility, which would not subject significant additional compliance obligations on the generator owner and/or operator.

169. In response to the question raised by PSEG Companies about whether the generation limit specified in exclusion E1(b) and (c) only applies to generators connected at 100 kV or higher, we note that exclusions E1(b) and (c) do not specify the generation connected to the radial system or local network to any voltage.

f. Normally Open Switches

NOPR Proposal

170. NERC included a note accompanying the description of exclusion E1 stating that “[a] normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.” NERC drafted this note to address a common network configuration in which two separate sets of facilities that, each standing alone, would be recognized as radial systems but are connected by a switch that is set to the open position for reliability purposes. In its petition, NERC explained that these switches are installed by entities to provide greater reliability to their end-use customers. NERC also explained that “a normally open switch” will be identified in

¹⁵¹ *E.g., New Harquahala Generating Company, LLC*, 123 FERC ¶ 61,173, *order on clarification*, 123 FERC ¶ 61,311 (2008).

documents such as prints or one-line diagrams and that “[t]he concept and usage of the ‘normally open switch’ in such configuration is well understood in the electric utility industry.”¹⁵²

171. In the NOPR, the Commission requested comment on NERC’s characterization and whether the phrase “normally open” is subject to interpretation or misunderstanding, or whether a “normally open” configuration is potentially difficult to oversee. The Commission also requested comment on the need of transmission operators or other functional entities to study the system impacts of the closing of a “normally open” switch, or to take other steps to ensure awareness of the impacts of the loop that is created by the closing of the switch if the closed loop is not included as part of the bulk electric system.

Comments

172. NERC explains that the term “normally opened” is well understood and commonly used in industry for a variety of reasons including public and personnel safety. NERC also explains that the purpose of recognizing a normally open switch in the definition is to preserve the bright-line so that the facilities can be characterized as they are planned to be operated which avoids the need to constantly reclassify elements to adjust to the changing operating conditions that occur on the system. NERC believes that a normally open switch is not difficult to oversee.

¹⁵² NERC BES Petition at 19.

173. Nearly all commenters that addressed this issue agree with NERC's positions.

NRECA highlights NERC's explanation that the configuration is so common that to write the definition to include radial systems connected by a normally open switch, with the caveat that entities can request an exception, would result in a flood of exception requests. Steel Manufacturers Association points out that such a switch can make a secondary connection point available to a large industrial load when needed to improve service reliability and continuity. Consumers Energy states that such switches would only be closed during emergency conditions and an entity in that instance would follow contingency plans and ensure that a proper study is performed on a normally open switch that is closed due to the emergency to avoid related equipment failures. TAPS agrees with NERC and notes that such switches are marked as normally open on one line diagrams.

174. PSEG Companies state that in effect the switch is irrelevant because if the normally open switch is open the systems are radial and therefore excluded and when the switch is closed the radial systems are also excluded for the same reasons figure 3 facilities should be excluded. Alameda submits it documents a normally open switch in operational diagrams and SCADA applications and its use is coordinated in advance with its transmission operator. Alameda also states that the system impacts of closing a normally open switch do not need to be required to be studied since it is the operational experience and documentation of such switch that is most important.

175. G&T Cooperatives state that some operational studies would be useful if there is an upcoming operational decision to close the normally open switch that could parallel

the bulk electric system. However, G&T Cooperatives explain that the study would be used to ensure that the system can operate with the switch closed without inadvertently tripping one of the source breakers. G&T Cooperatives explain that a normally open switch would not need to be modeled into any real-time model or contingency analysis, nor would it require the interconnecting radial systems to be incorporated into the bulk electric system, where such conditions are managed through quick changes to the equivalence bus loads or generation capacities. Similarly, TAPS states that closing a normally open switch does not have an impact on the system that needs to be studied because it is only close to change a down stream path on a temporary basis and does not create a loop.

Commission Determination

176. Upon consideration of comments, we are persuaded that the concept of a normally open switch is well understood, common and not difficult to oversee. We accept NERC's explanation that recognizing a normally open switch in the definition will preserve the bright-line so that the facilities can be characterized as they are planned to be operated and avoids the need to constantly reclassify elements to adjust to the changing operating conditions that occur on the system.

177. With regard to the Commission's question concerning the need to study the system impacts of the closing of a "normally open" switch, at this time we will not require them to be studied. We are persuaded that the operational experience and documentation of such switch is most important and, thus, we decline to require additional studies.

7. Exclusion E2 (Behind the Meter Generation)

NOPR Proposal

178. NERC stated in its petition that the wording of exclusion E2 is extracted from the Statement of Compliance Registry Criteria.¹⁵³ In the NOPR, the Commission stated that the exclusion of “[a] generating unit or multiple generating units on the customer’s side of the retail meter...” was an appropriate exclusion that provides additional clarity and granularity to the definition of bulk electric system.¹⁵⁴ While the Commission did not ask specific questions about exclusion E2, several commenters expressed support for the inclusion, while others stated concerns with the exclusion.

Comments

179. NERC and EEI agree with the Commission that the exclusion provides additional clarity. ELCON notes that such configurations are commonly employed by industrial users of electricity, and they do not affect in any significant way the bulk power system. On the other hand, ISO New England believes that exclusion E2 should be eliminated because it is contrary to the reliability of the bulk electric system. According to ISO New England, a 400 MW generator which is behind the meter with a 400 MW load could be excluded even though it could have a significant impact on the performance of the bulk electric system. ISO New England states that the owner of the generator in this example would not need to provide generator stability modeling information nor abide by

¹⁵³ NERC BES Petition at 22.

¹⁵⁴ NOPR, 139 FERC ¶ 61,247 at P 88.

the many normally applicable Reliability Standards. MISO believes that the exclusion could encourage entities to move generation capacity behind the meter which could adversely impact the bulk electric system.

180. PSEG Companies state that exclusion E2 could exclude generation included in inclusion I2. For example, PSEG Companies contends that, if a single 200 MVA behind-the-meter generator is connected to the bulk electric system at 100 kV or higher, the net capacity provided to the bulk electric system does not exceed 75 MVA and the generator has standby, backup, and maintenance services, under exclusion E2 the generator would be excluded from the bulk electric system, but it would be included pursuant to inclusion I2.¹⁵⁵

181. Other commenters, such as Barrick and the IUU, believe additional clarification is needed for the terms “retail meter” and “net capacity.” Specifically, they question what the capacity is “net” of or whether it means the sum of flows at all points of connection to the bulk electric system. They also question whether “net” means the capacity of a generator that is made available for use by someone other than an owner of the generator or capacity less parasitic load only.

182. Barrick and IUU believe there is more than one use for the term “retail meter,” and it is not clear whether all situations are covered by the use in the proposed exclusion E2. Barrick proposes that the term “retail meter” should include an end-user’s meter at an

¹⁵⁵ PSEG Comments at 14.

end-user's generator when that meter is used to measure the end-user's generation for consumption.

Commission Determination

183. We find that exclusion E2 provides additional clarity to the definition of bulk electric system, and we disagree that exclusion E2 is contrary to the reliability of the bulk electric system. We agree with ELCON that such configurations are commonly employed by industrial users of electricity. Indeed, this exclusion is similar to the exclusion for such facilities in NERC's Registry Criteria.¹⁵⁶ With regard to ISO New England's and PSEG Companies specific examples, to the extent such scenario exists, they may be eligible for inclusion or exclusion through use of the exception process.

184. We decline to define the additional terms cited by commenters, such as Barrick and the IUU, who believe additional clarification is needed for the terms "retail meter" and "net capacity." These terms are in common use in the electric power industry. Therefore, we do not see a need to adopt a formal definition.

8. Exclusion E3 (Local Networks)

NOPR Proposal

185. NERC's proposed exclusion E3 defines the term "local networks" as:

A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to

¹⁵⁶ NERC Statement of Compliance Registry Criteria, section III.c.4.

Load rather than transfer bulk-power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk-power transfer across the interconnected system.

Exclusion E3 also identifies three criteria that must be satisfied for the exclusion to apply:

(a) limit on connected generation to 75 MVA aggregate capacity of non-retail generation (gross nameplate rating); (b) power flows only into the local network and does not transfer through the local network; and (c) the local network is not part of a flowgate or transfer path.

186. In the NOPR, the Commission requested comment on: (1) whether generation resources are excluded by this exclusion; (2) how the exclusion applies to a looped lower voltage system; (3) whether the 300 kV ceiling is appropriate for the application of the exclusion; and (4) whether the prohibition for generation produced inside a local network is not transporting power to other markets outside the local network applies in both normal and emergency operating conditions.¹⁵⁷ The Commission also sought further explanation regarding the design and technical justification of a local network. These issues are discussed in detail in the following sections.

¹⁵⁷ NOPR, 139 FERC ¶ 61,247 at P 89.

a. **Local Network Design and Technical Justification**

NOPR Proposal

187. In the NOPR, the Commission requested explanation and comment on the statement in NERC's petition that "neither will the local network's separation or retirement diminish the reliability of the interconnected electric transmission network."¹⁵⁸

In its petition, NERC stated that the design and operation of local networks is such that at the point of connection with the interconnected transmission network is similar to that of a radial facility, in particular that power always flows in the direction from the interconnected transmission network into the local network.¹⁵⁹ Further, according to NERC, "[l]ocal networks provide local electrical distribution service and are not planned, designed or operated to benefit or support the balance of the interconnected transmission network."¹⁶⁰

188. In the NOPR, the Commission observed that, while a radial facility emanates from one point of connection to the interconnected transmission network, a local network by definition has multiple points of connection to the interconnected transmission network. Thus, regarding a local network, a contingency situation may arise where one of the multiple connections to the interconnected transmission network separates, while other local network connections maintain connectivity with the bulk electric system.

¹⁵⁸ NERC BES Petition, Exhibit G at 2. (Local Network Technical Justification).

¹⁵⁹ NERC BES Petition at 22.

¹⁶⁰ *Id.*

Accordingly, the Commission requested comments to better understand how an entity with a candidate local network would analyze such contingencies to determine potential impacts to the reliable operation of the interconnected transmission network.

Comments

189. EEI, MISO and other commenters generally support exclusion E3.¹⁶¹ With respect to the issue raised by the Commission regarding how an entity's local network separation will not diminish the reliability of the interconnected transmission network, NERC explains that the reliability of the interconnected transmission network is not impacted by the existence or absence of the local network. NERC maintains that excludable facilities under exclusion E3 will naturally satisfy this principle because the exclusion E3 conditions were crafted in such a way to ensure reliability is not adversely impacted by the disconnection of the local network. While specific analyses are not necessary to support exclusion of facilities under exclusion E3, NERC states that transmission operators or other functional entities need to be aware of the change of status of all devices on the system and the impact to the system from device changes. According to NERC, exclusion of a local network does not obviate the transmission operator or other functional entity from the responsibility to assess the system impact on any bulk electric

¹⁶¹ *E.g.*, NRECA, ELCON, BPA, and G&T Cooperatives.

system facility due to the separation of one local network connection while the remainder of the local network remains connected with the bulk electric system.¹⁶²

190. TAPS agrees with NERC stating “sophisticated engineering analysis should not be needed to determine the applicability of [i]nclusions and [e]xclusions.”¹⁶³ Likewise, WREA agrees with NERC’s assertion that the entity with a local network does not need to analyze local network contingencies since this analysis is already made by the transmission planner and transmission operator responsible for the bulk electric system facilities feeding the local network. Regarding the transmission planner responsibilities, WREA states the NERC Reliability Standard TPL-002 requires the transmission planner to study N-1 contingencies and prepare plans for reliable operation. WREA further explains that the transmission operator is required to plan to meet unscheduled changes in system configuration pursuant to Reliability Standard TOP-002, R6 and “if there are non-[bulk electric system] facilities that are significant, that have not been properly represented in a [transmission operator’s] models, [then] when the [transmission operator] performs its required model accuracy validation (TOP-002, R19), the [transmission operator] would observe a modeling inconsistency and would be able to take steps to correct the modeling error.”¹⁶⁴

¹⁶² NERC Comments at 26.

¹⁶³ TAPS Comments at 9.

¹⁶⁴ WREA Comments at 8-9.

191. AEP advocates for a baseline or cut-off point, which would be determined by the size (in MW) of the local network. Idaho Power believes that the statement means that total separation or loss of the local network elements does not cause a reliability performance impact on the remaining bulk electric system elements. Idaho Power explains that it would analyze such contingencies by evaluating overload levels and voltage performance impacts on the remaining bulk electric system elements as well as overload levels and voltage performance on the remaining local network elements.

192. Southern Companies state that such a contingency would be incorporated into planning studies regardless of whether the local network was part of the bulk electric system.¹⁶⁵ BPA believes that before a candidate local network is excluded, it must be evaluated by the impacted balancing authority, transmission operator and planning authority to ensure the integrity of the bulk grid is not compromised.¹⁶⁶

Commission Determination

193. The Commission approves exclusion E3. The Commission accepts NERC's explanation about the statement that "neither will the local network's separation or retirement diminish the reliability of the interconnected transmission network." The Commission also accepts NERC's comments relating to how an entity with a candidate local network would analyze such contingencies to determine potential impacts to the

¹⁶⁵ Southern Companies Comments at 13.

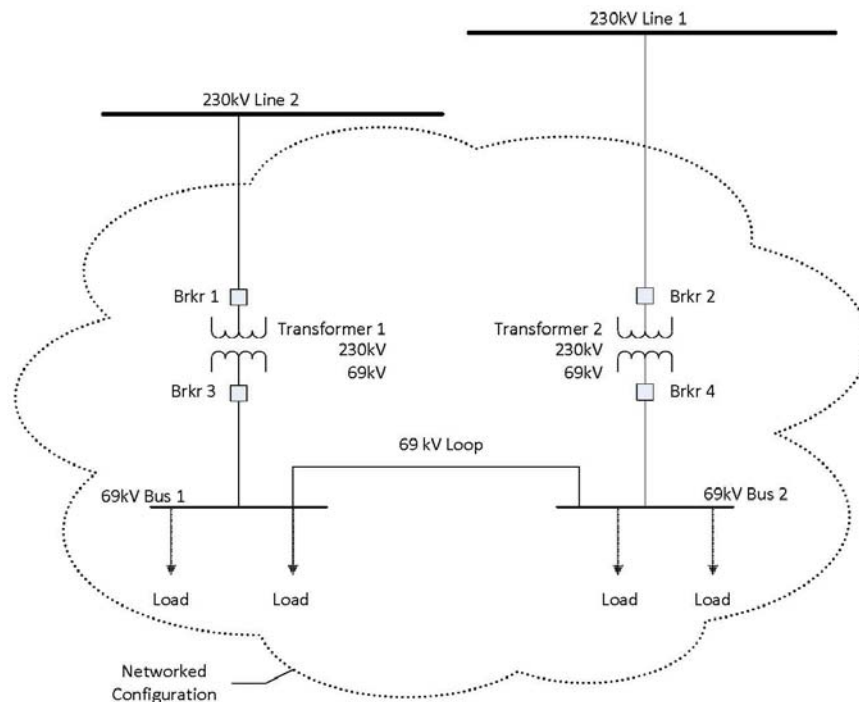
¹⁶⁶ BPA Comments at 7-8.

reliable operation of the interconnected transmission network. In particular, the Commission agrees that the exclusion of a local network does not obviate the transmission operator or other functional entity from the responsibility to assess the system impact of separating one local network connection while the remainder of the local network remains connected with the bulk electric system. We will not direct NERC to modify the provision as suggested by AEP and BPA. Rather, as NERC indicates, AEP and BPA may raise these suggestions with NERC in the Phase 2 development effort.

b. Figure 5, Contiguous Transmission Elements and the 100 kV Lower Limit

194. Exclusion E3 defines local networks as “[a] group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk-power across the interconnected system.” While the local network exclusion applies to contiguous transmission elements operating at a minimum of 100 kV, the Commission stated in the NOPR that it is unclear how the exclusion applies to a looped lower voltage system. The Commission provided an example of its concern depicted in figure 5 in the NOPR which shows a 69 kV looped system emanating from two points of connection at 100 kV or higher.

Figure 5
Networked Configuration w/69 kV Loop



195. In the NOPR, the Commission stated that figure 5 depicts a group of elements that are contiguous through a 69 kV loop and requested comment whether the configuration in figure 5 qualifies as a local network and, in particular, whether the configuration satisfies the conditions that a local network be contiguous and operated at or above 100 kV.

Comments

196. NERC views figure 5 the same as figure 3 - as a looped system below 100 kV - that is not considered under this exclusion because the elements below 100 kV are

presumed to be not part of the bulk electric system.¹⁶⁷ NERC maintains that, if it is determined that the sub-100 kV looped system is necessary for the reliable operation of the interconnected transmission network, the exception process may be utilized to include the appropriate elements. NERC states that figure 5 depicts two separate and distinct groups of elements that each emanate from a single point of interconnection at 230 kV and only serve load. Accordingly, NERC states that 230 kV lines 1 and 2 are included in the bulk electric system with the only other included elements being the lines extending from lines 1 and 2. However, according to NERC, the elements between 230 kV line 1 and transformer 2 and between 230 kV line 2 and transformer 1 are each subject to exclusion E1(a) because each separate set of elements is contiguous and emanate from a single point of connection of 100 kV or higher. NERC asserts that the elements below the 69 kV side of transformers 1 and 2 are excluded because they are less than 100 kV. NERC explains that transformers 1 and 2 are excluded because they bridge voltages of 69 kV and 230 kV and therefore, inclusion I1 is not applicable because a transformer must have two terminals over 100 kV to qualify for inclusion I1. According to NERC, the definition should focus on looped or networked connections at 100 kV or greater because such connections, when operated below 100 kV, generally do not carry

¹⁶⁷ Figure 5 and figure 3 set forth in the NOPR are identical configurations.

significant parallel flow because of the higher impedance associated with lower voltage facilities.¹⁶⁸

197. Exelon states that the clear intent of the definition is that configurations such as shown in figure 5 are radial systems subject to exclusion E1 (radial systems). According to Exelon, had this not been the intent of exclusion E1, exclusion E3 would have allowed for a local network where the tie was below 100 kV to avoid a reliability gap. Exelon believes that the configuration shown in figure 5, which is identical to figure 3, does not qualify as a local network within the terms of exclusion E3 and supports NERC's view that figure 5 represents two radial systems that qualify under exclusion E1. Exelon cautions that, if the Commission determines that the systems depicted in figure 5 do not qualify under exclusion E1 because of the low voltage tie and does not qualify under exclusion E3 because the tie is at low voltage and not a 100 kV or above, such a decision would leave a gap under which a substantial number of facilities that are not part of the bulk electric system would be classified as such. Exelon states that it would have to go through the separate exception process for dozens of substations, at great cost and for no useful purpose. Exelon states that the Commission should clarify that the configuration shown in figures 3 and 5 qualifies as a radial system and is excluded pursuant to exclusion E1.

¹⁶⁸ NERC Comments at 27-28.

198. Other commenters disagree with NERC's position. Idaho Power believes the network configuration with a 69 kV loop belongs to a local network category pursuant to exclusion E3 and that these types of networks should be studied to identify if there is any resulting voltage, overload, or stability violation that could propagate and impact the reliability of the system. Idaho Power believes that the 69 kV loop can tie the 230 kV systems together; therefore, outages in the 230 kV system could cause loop flow in the 69 kV system. According to Idaho Power, planning studies would have to be performed to determine the amount of loop flow and whether the loop flow could lead to outages on the 69 kV system, resulting in further impact to the bulk electric system.¹⁶⁹ WREA also notes figure 5 is the same as figure 3 and states that the 230 kV elements described in the figure would not qualify for the radial system exclusion E1 because the 230 kV elements are networked via facilities less than 100 kV. WREA concludes the elements above 100 kV in the figure might qualify for the local network exclusion and the below 100 kV facilities in this configuration are non-bulk electric system on the basis of the core definition unless the facilities are included via the exception process.¹⁷⁰ AEP believes that figure 5 could be considered for exclusion E3, provided that it is understood that at some point on the local network, the network could be of the size that would have a

¹⁶⁹ Idaho Power Comments at 11.

¹⁷⁰ WREA Comments at 9.

potential impact on the bulk electric system and would still need to meet the parameters of exclusion E3.¹⁷¹

Commission Determination

199. As discussed above, the Commission is directing a modification to exclusion E3 to better capture local networks like those depicted in figure 5. The Commission notes that Exelon believes that the configuration shown in figure 5, which is identical to figure 3, does not qualify as a local network within the terms of exclusion E3. While figures 3 and 5 are a networked configuration through a 69 kV loop, they do not qualify for the local network exclusion because exclusion E3 defines local networks as “[a] group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk-power across the interconnected system.” The configuration in figure 5 includes elements that are below 100 kV, and does not have contiguous elements operating at or above 100 kV but less than 300 kV. As noted above, while the Commission finds that these configurations should not be eligible for exclusion E1, we believe that they should be eligible for the local network exclusion. Therefore, we direct NERC to modify exclusion E3 to remove the 100 kV minimum operating voltage in the local network definition. Within 30 days of the effective date of this Final Rule, we direct NERC to submit a schedule outlining how and when it will make the modification to the definition.

¹⁷¹ AEP Comments at 10.

c. **300 kV Cap**

NOPR Proposal

200. NERC explained the selection of a 300 kV cap for the applicability of an exclusion for a local network was based upon recent NERC standards development work in Project 2006-02 “Assess Transmission Future Needs and Develop Transmission Plans” which sets a voltage level of 300 kV to differentiate extra high voltage (EHV) facilities from high voltage facilities acting as a threshold to distinguish between expected system performance criteria.¹⁷² In the NOPR, the Commission noted that NERC provided an example of the electrical interaction between a typical local network and the bulk electric system which depicted a local network operating at 115 kV. However, the Commission observed that NERC did not provide examples of a local network operating within the 200 to 300 kV range. The Commission expressed concern whether the 300 kV ceiling is appropriate and reflects actual system configurations that serve local distribution, the stated purpose of the local network exclusion. Thus, the Commission requested comment whether the 300 kV ceiling is appropriate for the application of exclusion E3 and requested examples of systems between 200 and 300 kV that would qualify for this exclusion.

¹⁷² NERC BES Petition at 23.

Comments

201. NERC asserts that the 300 kV cap is appropriate. NERC reiterates that the voltage cap is consistent with the distinction being made between extra high voltage and high voltage in the Reliability Standard TPL-001-2. NERC adds that the important attributes of a local network are the limit on capacity of connected non-retail generation, prohibition of power flow out of, or through, the local network, and prohibition of local networks containing flowgates or major transfer paths. NERC maintains that these attributes, rather than the operating voltage of the local network facilities, assure that local networks do not impact reliability of the interconnected transmission network.

202. Most commenters agree that the 300 kV threshold is appropriate.¹⁷³ With respect to the Commission's request for examples of systems between 200 and 300 kV that would qualify for this exclusion, ICNU states that, one of its members operates a large industrial facility that takes service from the bulk electric system from two transformers, both of which operate at 230 kV on the high side, but step down to 13.5 kV for distribution within the complex. According to ICNU, this industrial plant serves no reliability function and serves only the retail load, but if the ceiling for exclusion E3 were lowered to 200 kV, this network potentially would not be excluded because it contains some elements operating between 200-300 kV. ICNU believes that the function of a local network, rather than its voltage, is the critical factor in excluding it from the bulk

¹⁷³ *E.g.* National Grid, AEP, ICNU, and WPPC.

electric system and therefore, recommends a local network exclusion based on function, not voltage. Nonetheless, to the extent a ceiling is deemed necessary, ICNU states that the 300 kV threshold is appropriate.

203. WPPC supports the 300 kV ceiling and WPPC states that the ceiling reflect industry's extensive use of 115-230 kV system to provide distribution service through a local network. WPPC points out that in low density areas it is more economical to serve load using one 230 kV network rather than four 69 kV networks. WPPC adds that many 55 and 69 kV networks that serve towns and cities have been upgraded to 115 or 230 kV for economic, technical and environmental reasons, but raising the voltage does not change their function.

204. In contrast, BPA, Hydro One, and WREA express concern regarding the 300 kV cap. BPA states that the 300 kV ceiling may not "reflect[] actual system configurations that serve local distribution, the stated purpose of the local network exclusion."¹⁷⁴ BPA believes that exclusion E3 should not apply to any facility above 200 kV, without appropriate review, analysis, and concurrence, from the impacted transmission operator, planning authority, and reliability coordinator. BPA states that fault magnitudes on systems between 200 kV and 300 kV are much higher than fault magnitudes on systems operated below 200 kV. According to BPA, these systems have a much higher potential for serious impacts than networks operating below 200 kV if something fails to operate

¹⁷⁴ BPA Comments at 8.

properly, including cascading outages, transient instability, and post transient voltage instability.

205. Hydro One believes that the 300 kV cap associated with the applicability of exclusion E3 is not justifiable on technical grounds, and submits that certain systems with greater than 300 kV should be able to qualify for exclusion E3 based on their own merits.

Hydro One states that a radial or a local network below 300 kV can have as much or more impact on the reliability of the interconnected transmission network than a local network operating at 300 kV or above depending upon its location and configuration.

WREA also disagrees with the 300 kV ceiling and recommends that the Commission delete this limitation entirely.

Commission Determination

206. The Commission approves the 300 kV voltage threshold for local networks for the initial implementation of the definition. While we approve the 300 kV threshold, the limited number of examples provided for 200-300 kV systems cause us to seek additional information. Thus, following implementation when actual exclusion data is available, the Commission directs NERC to submit a compliance filing within one year of the implementation date identifying in sufficient detail the types of local network configurations that have been excluded from the bulk electric system under this exclusion. This will assist us in better understanding the type and magnitude of systems that fall into above 200 kV category.

d. Criterion (a) – Limits on Connected Generation

NOPR Proposal

207. Exclusion E3 criterion (a) provides that the local network and its underlying elements do not include the blackstart resources identified in inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA gross nameplate rating. In addition, criterion (a) does not limit the amount of generation besides “non-retail generation” connected to the local network. The Commission stated in the NOPR that it agrees with NERC that “local networks” do not include blackstart resources and agrees with the limits on the connected generation imposed by this exclusion. The Commission also stated that similar to the discussion of the definition of “radial systems” in exclusion E1, the exclusion E3 local network exclusion applies to “transmission Elements,” but does not exclude generation resources connected to a local network that otherwise satisfy inclusion I2.

Comments

208. NERC concurs with the Commission’s statement that “local networks” do not include blackstart resources and agrees with the limits on the connected generation imposed by this exclusion. NERC, EEI, Alameda, Hydro One, and WREA state that, whether or not generation is included in the bulk electric system is determined by inclusions I2 through I4 and exclusion E2. In addition, NERC confirms that exclusion E3 does not exclude generation resources.

209. In contrast, some commenters are concerned about allowing generators identified in inclusion I2 to be connected to local networks. Idaho Power states that it is not

appropriate to exclude a local network if it contains generation that would normally be included in the bulk electric system through inclusion I2.¹⁷⁵ PSEG Companies states that “there is confusion created by the fact that generators included in the [bulk electric system] definition per [inclusion] I2 are at the same time excluded under [exclusions] E2 and E3.”¹⁷⁶ According to PSEG Companies, a generator cannot be included under one provision of the bulk electric system definition and excluded under another provision and that this issue requires clarification and, once clarified, the bulk electric system definition needs to be modified accordingly.

210. Some commenters seek clarification of exclusion E3 criterion (a) regarding the term “non-retail.”¹⁷⁷ Barrick and the IUU raise several questions about exclusion E3. First, they claim that the phrase “not . . . non-retail generation” is unclear and question whether it means generation used for retail. They also question whether exclusion E3 excludes generation resources for an owner’s own use or generation used for wholesale. They also ask how the term “non-retail” relates to “net capacity.”

211. While Holland supports the exclusion of local networks from the bulk electric system, Holland argues that criteria (a) and (b) should be eliminated because they limit the amount of connected generation, even where the connected generation is distributed

¹⁷⁵ Idaho Power Comments at 10.

¹⁷⁶ PSEG Comments at 11.

¹⁷⁷ *E.g.*, Barrick, IUU, and PSEG.

locally. Holland states that exclusion E3(a) improperly maintains the aggregate 75 MVA limit for connected generation. Holland believes this limit is inconsistent with the concept of a local network and should be removed. Holland explains that if the local network does not accommodate bulk power transfer across the interconnected system, then the amount of generation that exists and is distributed within that system, regardless of size, is distributed and consumed locally, and is therefore beyond the scope of FPA Section 215. Holland maintains that, if the Commission does not remove exclusion E3(a) in its entirety, it should require the limitation to be based on the net of the local network's total load, rather than the gross nameplate rating.

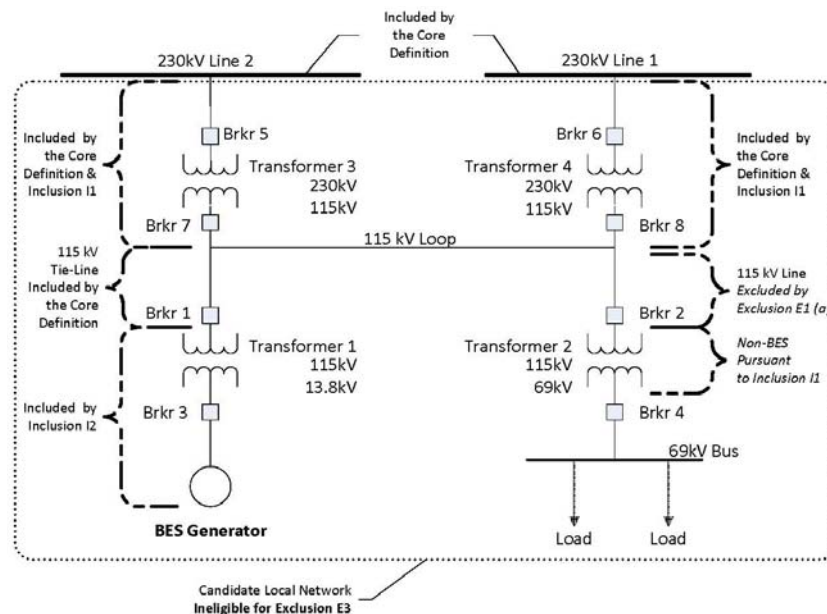
212. NESCOE contends that three conditions in exclusion E3 would unnecessarily include some New England networks in the bulk electric system without any clear reliability benefit. In particular, NESCOE states that the limits on connected generation should be raised to 300 MVA instead of 75 MVA, stating that the northeast portion of the eastern interconnection defines a 1200 MVA loss of source as the largest contingency to which the control area is designed to operate. Therefore, NESCOE believes that 25 percent of that contingency at 300 MVA falls well within typical loss of source expectations for the northeast. Alameda suggests that the Commission raise the connected generation limitation for local network exclusions to 150 MVA. According to Alameda, since the local network is comparable to two radials, limiting a local network to 75 MVA could result in entities choosing to operate two less reliable radial systems, each with 75 MVA of generation, rather than one local network with 150 MVA of generation to avoid a designation as bulk electric system for their local network.

Commission Determination

213. We find that the local network exclusion only applies to “transmission Elements” and does not allow the exclusion of generation resources otherwise included in the bulk electric system pursuant to inclusion I2, as discussed above in our determination regarding exclusion E1.

214. Further, as discussed above regarding exclusion E1, the Commission agrees with Idaho Power, PSEG Companies, SmartSenseCom, and AEP that tie-lines for generators identified in the inclusion I2 should not qualify for exclusion as radial systems or local networks. Rather the tie-lines can be considered for exclusion under NERC’s exception process. Accordingly, consistent with the Commission’s directive discussed above regarding exclusion E1, the Commission directs NERC to implement exclusion E3 so that the exclusion for local networks does not apply to bulk electric system generator tie-lines operated at or above 100 kV as shown in the figure below.

115 kV Loop with BES Generation



215. In response to Barrick's and IUU's requests for clarification, we decline to clarify the terms/phrases "non-retail," "gross plant/facility," "not necessary," "aggregate," "net capacity," and "retail meter." We believe the terms/phrases are sufficiently clear.

However, Barrick and IUU may pursue further clarification from NERC in an appropriate forum such as NERC's Phase 2 project.

216. With regard to the comments of Holland, NESCOE and Alameda, we will not direct any change in the connected generation limitation for the local network exclusion. The limit on connected generation within the local network is consistent with the existing threshold above which a generating plant in aggregate becomes subject to registration under the NERC Registry Criteria. Entities may avail themselves of the exception

process to exclude a local network that otherwise does not qualify pursuant to exclusion E3.

e. **Criterion (b) – Power Flows only into the Local Network**

NOPR Proposal

217. Exclusion E3 criterion (b) specifies that, to qualify for the exclusion, power can only flow into the local network and the local network does not transfer energy originating outside the local network for delivery through the local network. The Commission noted in the NOPR that, pursuant to criterion (b), generation produced inside a local network is not transporting power to other markets outside the local network. The Commission stated in the NOPR that it understands that criterion (b) applies in both normal and emergency operating conditions.¹⁷⁸

Comments

218. NERC confirms, and TAPS, Idaho Power and others concur with the Commission's understanding that, pursuant to criterion (b), generation produced inside a local network is not transporting power to other markets outside the local network. NERC and other commenters also agree that criterion (b) applies in both normal and emergency operating conditions.

¹⁷⁸ See NOPR, 139 FERC ¶ 61,247 at P 98 (citing NERC BES Petition, Exh. E at 59 (“The Commission directed NERC to revise its BES definition to ensure that the definition encompasses all Facilities necessary for operating an interconnected electric Transmission network. The SDT interprets this to include operation under both normal and Emergency conditions....”))).

219. NERC states that prohibitions on outbound power flow and transportation of power to other markets beyond the local network apply in all conditions, both normal and contingent, and will eliminate the exclusion of facilities which may contribute power flow into the bulk electric system under contingent or unusual circumstances. According to NERC, basing the determination solely on normal conditions could lead to inconsistent application of this exclusion and would introduce subjectivity into the application of the definition.

220. Duke Energy agrees with NERC's comment that prohibitions on outbound power flow beyond the local network apply in "both normal and contingent conditions," but believes that "contingent" should be further clarified as limited to N-1 contingencies for the bright line definition. Idaho Power also agrees, and comments that additional clarification is needed to define whether the meaning of "emergency conditions" includes contingencies within the local network itself. In contrast, Southern Companies states that criterion (b) would apply in normal but not emergency operating conditions. MISO cautions against precluding local networks from sending electricity to the transmission system in emergency conditions when doing so could improve the availability of electricity.

221. Portland notes that the application of criterion (b) in both normal and emergency operating conditions is similar to one element of the Seven Factor Test that states that power rarely if ever flows out. Portland suggests that the Commission should clarify the relationship between the Seven Factor Test and the local distribution exception in the reliability regulatory context.

222. Alameda believes that the power flow prohibition should apply only where the flow from the local network is necessary for the reliable operation of the interconnected transmission network. Alameda contends that these conditions would typically apply during peak or near-peak operating conditions and that it would be inappropriate to include a local network in the bulk electric system because generation flowed outside the local network only under off peak conditions when these flows were not vital to reliability. Alameda suggests that the power flow prohibition be modified to allow flows of less than 75 MVA to flow outside the network, making the local networks electrically comparable to radial systems with a 75 MVA generator.

223. ISO New England believes the NOPR suggests an implicit expectation regarding the determination of local networks in that there is no stated requirement for contingency analyses in that determination. ISO New England believes that the Commission understanding of criterion (b) implies that criterion (b) needs to be analyzed both pre- and post-contingency. In such a case, this issue needs to be defined in the exclusion. Additionally, ISO New England requests clarification whether this indicates that one must apply a first contingency to the analysis or a second contingency in determining if the criterion is met.

224. Dow asserts that the requirement that power may only flow into a local network should be clarified to apply only to power that originates outside of, and flows through, a local network. Dow believes that it should not apply to power generated by non-retail generation resources meeting applicable size or export quantity thresholds that are connected to local networks. Dow maintains such a clarification is consistent with other

language in the exclusion specifying that up to 75 MVA of non-retail generation may be attached to a local network. Dow views the reference to non-retail generation as intended to apply to generation resources that are used to make wholesale sales which requires that power be able to flow into the bulk electric system for delivery to downstream buyers.

Dow also states that exclusion E3 should be clarified to address situations in which a local network does not qualify for the local network exclusion because it is not clear “whether all facilities rated 100 kV and above that are part of the local network would be considered part of the [bulk electric system] and become subject to transmission-related reliability standards....”¹⁷⁹

225. Valero contends that criterion (b) indicates that the existence of a power flow that “transfers through the local network” would disqualify an element from satisfying the exclusion. On the other hand, Valero points to the excerpt from the NERC BES Petition which implies that this meaning of criterion (b) might not be the appropriate interpretation.¹⁸⁰ Valero requests that the Commission either clarify as stated above or modify criterion (b) to allow for transfers through the local network if such transfers are not necessary for the reliability of the interconnected transmission network.

¹⁷⁹ Dow Comments at 6.

¹⁸⁰ The NERC statement is quoted in the NOPR at P 81: “[l]ocal networks provide local electrical distribution service and are not planned, designed or operated to benefit or support the balance of the interconnected transmission network.”

226. NESCOE and G&T Cooperatives state that minimal transfers may and do occur, and local networks should not necessarily be ineligible for exclusion E3 simply because some amount of power may transfer out of the network. NESCOE states that the Commission should direct NERC to reevaluate exclusion E3 to allow these minimal flows up to a 100 MVA limit.¹⁸¹ G&T Cooperatives state that even with optimal load projections, there may be times when energy flows into the local network that exceed the load, and in those cases the local network may need to export the excess energy back to the bulk electric system which could create perverse incentives to restrict flows into and out of the local network. G&T Cooperatives suggest that criterion (b) should be read to allow exclusion E3 to cover local networks in which “normally” power flows into the local network and the local network does not transfer energy originating outside the local network for delivery through the local network.

227. Holland states that the exclusion E3(b) criterion is unnecessary and should be removed. Holland states that exclusion E3(b) appears to be concerned with flows originating from outside of the local network, coming into the local network, and then exiting the local network to loads outside of the local network. According to Holland, however, exclusion E3(c) appears to address this concern because it fails to recognize that a local network may have internal generation that is less than its peak load but in excess of off-peak load levels. Holland states that, if exclusion E3(b) is maintained, then

¹⁸¹ NESCOE states that this represents 25 percent of the rated value of a typical 345/115 kV substation.

the clause, “[p]ower flows only into the [local network],” should be deleted because it is inconsistent with the second clause, “the [local network] does not transfer energy originating outside the [local network] for delivery through the [local network].”

Commission Determination

228. The Commission finds that: (1) pursuant to exclusion E3 criterion (b), generation produced inside a local network should not transport power to other markets outside the local network; and (2) exclusion E3 criterion (b) applies in both normal and emergency operating conditions. The Commission agrees with NERC’s statements that basing the determination solely on normal or optimal conditions could lead to inconsistent application of this exclusion and hence the definition itself, and would also introduce a degree of subjectivity in the application of the definition that is not in the interest of reliability.

229. MISO and other commenters suggest that local networks should be allowed to deliver power to the bulk electric system in some circumstances.¹⁸² The Commission agrees that the facilities should supply such power if needed, but disagrees that facilities expected to be needed in this way should nonetheless be excluded from the bulk electric system. If a local network is expected to be needed to operate the interconnected transmission network, i.e., to meet reliability performance criteria in transmission planning assessments, it should not be excluded from the bulk electric system under

¹⁸² *E.g.* Southern Companies, Alameda, Dow, Valero, NESCOE, Holland and G&T Cooperatives.

exclusion E3. The Commission also rejects Holland's suggestion to remove criterion (b) because NERC has presented an acceptable technical justification for this and the other criteria in exclusion E3.¹⁸³ In response to Alameda's comment that some power should be permitted to flow out of a local network during off-peak hours, the Commission disagrees that the bright-line definition should be modified for case-specific circumstances. Entities can seek to exclude configurations that do not meet the exclusion E3 criteria through the exception process on a case-by-case basis. The Commission agrees with Portland that criterion (b) is similar to one element of the Seven Factor Test but otherwise addresses what constitutes local distribution above.

230. In response to Idaho Power and ISO New England asking for how emergency conditions are defined to determine if a candidate configuration meets exclusion E3 criterion (b), the Commission believes that the best way to show that a local network meets criterion (b) is through historical power flow data.

231. We will not direct NERC to allow minimal flows up to a 100 MVA limit as NESCOE requests. NESCOE may choose to pursue this matter further with NERC, with the Phase 2 project being one appropriate forum. Similarly, Dow may raise its contention that exclusion E3 should not apply to certain non-retail generation resources during Phase 2. Regarding Dow's argument that exclusion E3 should be further clarified, we believe our discussion above regarding figure 5 adequately addresses Dow's concern.

¹⁸³ NERC BES Petition at 22-24.

f. Criterion (c) – Not Part of a Flowgate or Transfer Path

232. Exclusion E3 criterion (c) specifies a “local network” does not contain a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Quebec Interconnections, and is not a monitored facility included in an interconnection reliability operating limit. NERC stated that the presence of a local network is not for the operability of the interconnected electric transmission network; neither will the local network’s separation or retirement diminish the reliability of the interconnected electric transmission network.”¹⁸⁴ The Commission stated in the NOPR that it believes that this is an appropriate criterion.

Comments

233. G&T Cooperatives state that criterion (c) should be clarified to allow local networks to come under exclusion E3 even if they are interconnected with a “monitored facility of a permanent Flowgate” in the Eastern Interconnection or a “major transfer path” in the Western interconnection. G&T Cooperatives recognize that such monitored facilities and major transmission paths are important to reliability, but criterion (c) could be read in a manner that would prevent a local network interconnected with such major facilities from qualifying under exclusion E3. G&T Cooperatives do not believe that NERC intended such a broad reading.

¹⁸⁴ NOPR, 139 FERC ¶ 61,247 at P 93 (citing NERC BES Petition, Exhibit G at 2).

Commission Determination

234. The Commission finds that exclusion E3 criterion (c) is an appropriate criterion. We agree with NERC that facilities with, e.g., permanent flowgates, cannot be included in a local network as the separation of such facilities during a system event could have an adverse impact on the operation of the interconnected transmission network. The language for criterion (c) only prohibits flowgates and their associated monitored elements from being within a candidate local network. Therefore, we believe the language is sufficiently clear and will not direct NERC to modify this provision in response to G&T Cooperatives request for clarification.

9. Exclusion E4 (Reactive Power Devices)**NOPR Proposal**

235. Exclusion E4 excludes from the bulk electric system “Reactive Power devices owned and operated by the retail customer solely for its own use.” NERC explained that exclusion E4 is the technical equivalent of exclusion E2 for reactive power devices and that the currently effective bulk electric system definition is unclear as to how these devices are to be treated. In the NOPR, the Commission stated that this is an appropriate exclusion that provides additional clarity and granularity to the definition of bulk electric system.

Comments

236. NERC, ELCON and EEI support the Commission’s proposal. Steel Manufacturers Association supports a definitive exclusion for reactive power equipment that is installed and used to benefit end use loads. The exclusion, however, in the

Steel Manufacturers Association's opinion, should not be confined to such devices that are owned and operated by a retail customer solely for its own use because there are instances in which capacitor banks have been installed for the benefit of a steel-making facility but, for various reasons, that equipment is owned, operated and maintained by its local utility. Consequently, the Steel Manufacturers Association suggests that exclusion E4 be revised to read: "Reactive Power devices owned and operated by, or installed solely for the benefit of, retail customers."

Commission Determination

237. The Commission finds that exclusion E4 is an appropriate exclusion that provides additional clarity and granularity to the definition of bulk electric system. In response to the Steel Manufacturers Association, we will not direct the suggested clarifying change to exclusion E4 criterion. Rather, Steel Manufacturers Association may choose to pursue this matter further with NERC in its Phase 2 project.

E. The NERC Rules of Procedure Exception Process, RM12-7-000

NOPR Proposal

238. As described above in section I.D.2, NERC proposed revisions to its Rules of Procedure to provide an "exceptions process" to add elements to, and remove elements from, the bulk electric system, on a case-by-case basis. NERC stated, *inter alia*, that the exception process decisions to approve or disapprove exception requests will be made by NERC, rather than by the Regional Entities.

239. In the NOPR, the Commission proposed to find that, pursuant to section 215(f) of the FPA, the exception process is just, reasonable, not unduly discriminatory or

preferential, and in the public interest and satisfies the requirements of section 215(c). Further, the Commission proposed to find that the proposed exception process satisfies the statement in Order No. 743 that NERC establish an exception process for excluding facilities that are not necessary for the reliable operation of the interconnected transmission network from the definition of the bulk electric system.¹⁸⁵

Comments

240. Many commenters support the exception process as proposed. Commenters state that the exception process will be able to handle the more unusual situations that need to be addressed on a case-by-case basis, including sub-100 kV transmission elements that are necessary for the reliable operation of the interconnected transmission network.¹⁸⁶ They further state that the exception process balances the need for effective and efficient administration with due process and clarity of expectations and promotes consistency in determinations and eliminates regional discretion by having all decisions on exception requests made at NERC. Southern Companies support approval of the exception process and assert that the Commission should allow time for NERC, Regional Entities and industry to implement the definition and exception process and determine at a later date whether it is sufficiently capturing the appropriate facilities.

¹⁸⁵ See NOPR, 139 FERC ¶ 61,247 at PP 103-04 (citing Order No. 743, 133 FERC ¶ 61,150 at P 16).

¹⁸⁶ *E.g.*, ELCON, TAPS, and Southern Companies.

241. MISO states that RTOs, as reliability coordinators, planning coordinators or authorities, and balancing authorities, should be allowed to file exception requests.

MISO also states that there should be fewer requirements for filing exception requests by RTOs because they have been assigned substantial authority over facilities under their authority by their member transmission owners and operators, and because they utilize rigorous stakeholder processes. Specifically, MISO requests that the Commission direct NERC to modify the exception process to recognize RTO stakeholder processes and their results as evidence that the RTO as the submitting entity conferred with the owner about the reasons for an exception and either an agreement was reached between the entities that an exception should be filed and that the RTO should submit the exception, or that the entities could not reach agreement regarding the submission of such an exception request.

242. NYISO comments that the exception process needs to provide interested parties notice and an opportunity to be heard. NYISO states that ISOs and RTOs have an interest in participating in an exception proceeding prior to a final determination by the Regional Entity or NERC because exception requests may affect them operationally or in their planning studies depending upon the final determination made on the specific exception request.

243. NYPSC and NESCOE are concerned that NERC's proposal does not give state commissions an opportunity to participate directly in the process. NESCOE states that, without state participation, NERC will not address the full range of substantive concerns that may arise in any given case, and, if the Commission is asked to review an exemption

determination, the record presented will not reflect the states' views. NESCOE is also concerned that the exceptions process lacks a mechanism for a state regulatory authority to initiate review of the classification of an element. NESCOE contends that states may have an interest in the proper classification of bulk electric system facilities, but they are not in a position to submit an exception request because they lack the detailed information required for a submission under the proposal. NESCOE suggests that this can be remedied by allowing a state to request a review from the relevant Regional Entity and to require the Regional Entity to submit a formal exception request if it finds that the classification is inaccurate. In addition, NESCOE believes that a state should have a right to seek review from NERC of the Regional Entity's determination.

244. In reply comments, NERC disagrees with MISO and explains that the exception process needs to be applied consistently and that the required information should be the same regardless of the identity of the submitter. NERC states that the Detailed Information Form is intended to ensure that a consistent baseline of technical information is provided to the Regional Entity and NERC with all exception requests, in addition to the specific information and arguments submitted by the submitting entity in support of its exception request. The MISO Transmission Owners and AMP support NERC's comments.

245. NERC also explains that RTOs and ISOs have the ability to file an exception request where they are acting in their capacity as planning authorities, reliability coordinators, transmission operators, transmission planners, or balancing authorities. NERC states that "the exceptions process is technical and is based on engineering

expertise, and these are the necessary parties with the required information.”¹⁸⁷ NERC also disagrees regarding a state or third party role and the need for notice and access to information. NERC states that state commissions have other means and methods at their disposal for working with entities to identify candidates for an exception request. NERC notes that the exception process provides that detailed notice of any request would be provided to every registered entity with reliability oversight obligation (e.g., planning authorities, reliability coordinators, transmission operators, transmission planners, or balancing authorities) for the element subject to the request and that general information about an exception request will be publicly posted. NERC also notes that third parties including state regulatory agencies will have adequate opportunity to provide comments regarding the request without formally participating in the process.

246. ICNU states that the Commission should make clear that utilities and Regional Entities, not end-use customers should be required to perform the studies to determine if a facility of an end-use customer should be included or excluded. Alameda suggests that the Commission set forth a future date for review of the definition seeking both an effectiveness report from NERC as well as industry comment.

247. IUU and Barrick believe that NERC’s explanation that an exception may be obtained by showing that the element is “not necessary” for reliable operation of the interconnected transmission system is too ambiguous and does not give adequate

¹⁸⁷ NERC Reply Comments at 5.

information as to what may or may not be eligible for an exception. They believe guidance is necessary as to the types of evidence that should be presented in an exception request and the criteria to which the evidence will be subjected.

248. Redding states that the exception process provides that entities are not required to use the exception process to affirmatively demonstrate they fall within the general local distribution carve-out in the core definition or meet one of the exclusions. Redding notes that new section 509 of the Rules of Procedure states that application of the entire definition will determine what facilities qualify as bulk electric system components. Therefore, Redding argues that section 509 confirms that no exception request is necessary if the facility fits within either the local distribution carve-out language of the core definition, or the explicitly identified exclusions. Furthermore, Redding argues that this is confirmed by NERC's statement that the definition expressly excludes both "facilities used in the local distribution of electric energy," and radial systems as described in Exclusion E1 of the definition. Redding believes this statement recognizes that facilities that are excluded from the definition at the outset - through either the core definition or the specific exclusions - need not submit any requests through the exemption process confirming that exclusion.

249. Holland is concerned that the exception process is too narrowly focused on excluding facilities that are not necessary for the reliable operation of the interconnected transmission network. Holland does not believe that exceptions should be limited to a demonstration that the facilities lack a material impact to the bulk electric system. Holland supports the exception process for this purpose; however, the lack of materiality

demonstration is independent of the question of whether the facilities should be excluded on the grounds that they are used in local distribution. Holland believes the Commission should clarify that, for exceptions seeking exclusion based upon a claim of being local distribution, NERC must evaluate additional information submitted, and not merely rely on the criteria in Exclusions E1 through E4.

250. Steel Manufacturers Association is concerned that because the Rules of Procedure provide that only a Regional Entity may submit an exception request for the inclusion in the bulk electric system of an element owned by an owner that is not a registered entity, they do not contemplate that the owner will be notified that its facilities are being considered for inclusion in the bulk electric system.

Commission Determination

251. Pursuant to FPA section 215(f), we approve the NOPR proposal and find that the exception process is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Further, we find that the proposal satisfies the statement in Order No. 743 that NERC establish an exception process for excluding facilities that are not necessary for the reliable operation of the interconnected transmission network from the definition of the bulk electric system.¹⁸⁸ The exception process balances the need for effective and efficient administration with due process and clarity of expectations and promotes consistency in determinations and eliminates regional discretion by having all decisions

¹⁸⁸ See Order No. 743, 133 FERC ¶ 61,150 at P 16.

on exception requests made at NERC. The exception process also provides for involvement of persons with applicable technical expertise in making decisions on exception requests and allows for an entity to appeal a final NERC decision to the Commission.

252. The exception process provides a reasonable mechanism for the ERO to determine whether a facility or element should be added to, or removed from, the bulk electric system on a case-by-case basis. However, for the reasons explained above in our discussion in section II.C regarding local distribution, the case-by-case determination of whether an element or facility is used in local distribution will be decided by the Commission.

253. We also find that NERC's explanation, that it was not feasible to develop a single set of technical criteria that would be applicable to all exception requests so it developed the Detailed Information Form (discussed in detail below) to ensure that a consistent baseline of technical information is provided for NERC to make a decision on all exception requests, is reasonable. We find that this information, coupled with the proposed exception process, allows NERC to provide consistent determinations on exception requests submitted from different regions involving the same or similar facts and circumstances, and allows NERC to take into account the aggregate impact on the bulk electric system of approving or denying all the exception requests. Thus, we find that NERC's proposal is clear, transparent, and uniformly applicable and is as equally efficient and effective as the Order No. 743 directive to establish an exception process for

excluding facilities that are not necessary for the reliable operation of the interconnected transmission network.

254. We are not persuaded by Barrick's and IUU's comments that more guidance is necessary. Order No. 743 tasked NERC with developing a revised definition and exemption process. NERC noted that it was not feasible to develop a single set of criteria. The Commission believes that applying the 100 kV threshold in the definition, the inclusions and exclusions and the information required in the Detailed Information Form will be a sufficient starting point to enable the ERO to make determinations as to whether an element is necessary for reliable operation of the interconnected transmission network. The body of exception decisions that NERC promulgates will further assist entities in presenting the relevant facts and circumstances when seeking an exception.

255. In response to MISO's request, we note that RTOs and ISOs, in their capacity as planning authorities, reliability coordinators, transmission operators, transmission planners, or balancing authorities, have the ability to file an exception request.¹⁸⁹ We are not persuaded that fewer requirements should apply to exception requests submitted by RTOs and ISOs, and we agree with NERC, MISO Transmission Owners and AMP that the exception process needs to be applied consistently and that the required information should be the same regardless of the identity of the submitter.

¹⁸⁹ See NERC ROP Petition, Attachment 1, Proposed Appendix 5C, Section 4.1.

256. NYISO comments that the exception process should provide interested parties - particularly ISOs and RTOs - notice and an opportunity to be heard. As we note above, the exception process affords ISOs and RTOs, in their capacity as planning authorities, reliability coordinators, transmission operators, transmission planners, or balancing authorities, notice and opportunity to comment on elements within their scope of responsibility.

257. Similarly, with regard to NYPSC's and NESCOE's comments on the role of state commissions in the exception process, we believe that NERC's proposal is reasonable and provides an adequate opportunity for state regulator participation. Specifically, NERC explains in its ROP petition that, in developing the proposed Rules, state regulators and others raised concerns about their ability to participate in the exception process. NERC responded that "the exception process should be one based on the technical reliability issues of the specific case presented.... [A] procedure that encouraged or even invited multi-party filings would unduly complicate the process without any concomitant benefit in reliability."¹⁹⁰ However, to provide transparency and some opportunity for participation, the proposed exception process provides that "(1) detailed notice of any request would be provided to every Registered Entity with reliability oversight obligation for the Element subject to the Request and (2) general

¹⁹⁰ NERC ROP Petition, Att. 9 ("The Development Process and Basis for the ROP Team's Recommended Provisions - How Stakeholder Comments were Considered and Addressed") at 7.

information about the request will be publicly posted,” thereby allowing third parties including state regulators “adequate opportunity to provide comments regarding the request without formally participating in the process.”¹⁹¹ We agree that NERC’s proposal strikes an appropriate balance between efficient processing of highly technical decisions and the opportunity for states and other entities to comment in the exception process. Nonetheless, as discussed above, requests for exclusion from the bulk electric system on local distribution grounds will be determined by the Commission on a case-by-case basis. In such proceedings, state regulatory authorities will have an opportunity to intervene and provide comments.

258. We disagree with Redding’s characterization of how the exception process is not necessary for determining whether an element is used for local distribution. Redding’s characterization of the exception process leaves the determination of whether an element is used for local distribution in the hands of registered entities or NERC. However, as we explain in the local distribution discussion above, in circumstances where there is a factual question as to whether facilities not otherwise excluded from the bulk electric system by the core definition and four exclusions should nonetheless be excluded because they are used in local distribution, a determination should be made by this Commission. In addition, in our discussion in section II.C above regarding local distribution, we

¹⁹¹ *Id.*

provide direction with respect to how an entity may seek a determination of whether an element is used in local distribution.

259. Regarding Steel Manufacturers Association’s concern that the Rules of Procedure do not contemplate that an owner of an element that is not a registered entity will be notified by a Regional Entity that its facilities are being considered for inclusion in the bulk electric system, we note that section 4.1 of Appendix 5C the Rules of Procedure states that when a Regional Entity requests an exception, the Regional Entity “shall prepare and submit copies of its exception request (or portions thereof) to all applicable entities...”¹⁹² Further, section 4.4 of Appendix 5C provides that, if the submitting entity is not the owner (i.e., is a Regional Entity, planning authority, balancing authority, etc) it must provide a copy of the exception request to the owner. Therefore, if a Regional Entity submits an exception request for an element owned by a non-registered entity, the owner is notified.

260. With respect to Holland’s request for clarification for what must be submitted for a claim of being local distribution, we believe that our discussion above regarding how local distribution elements will be determined addresses Holland’s concerns.

261. In response to ICNU’s comments, the Commission notes that NERC has identified the entities that are responsible for providing the information necessary for an exception request. Section 3.2 of the exception process states that “the burden to provide a

¹⁹² NERC Rules of Procedure, Appendix 5C, section 4.1.

sufficient basis for approval of an exception request in accordance with the provisions of the exception procedure is on the submitting entity.” Additionally, in section 4.1 of the exception process, NERC lists the eligible submitting entities as the owner of an element, or a Regional Entity, planning authority, reliability coordinator, transmission operator, transmission planner, or balancing authority that has (or will have upon inclusion in the bulk electric system) the elements covered by an exception request within its scope of responsibility.

262. Southern Companies state that the Commission should allow time for NERC, Regional Entities and industry to implement the definition and exception process and determine at a later date whether it is sufficiently capturing the appropriate facilities. Similarly, Alameda suggests that the Commission set forth a future date for review of the definition seeking both an effectiveness report from NERC as well as industry comment. First, as discussed below, the Commission is granting NERC’s request for a 24 month implementation plan. The Commission believes that this is sufficient to implement the definition and exception process. In addition, the Commission declines to set a future date to determine effectiveness of the definition and the exception process.

1. How Entities Will Review and Seek Inclusion of Necessary Elements

NOPR Proposal

263. In Order Nos. 743 and 743-A, the Commission indicated that our goal is that the definition of bulk electric system should include all facilities necessary for the operation of the interconnected transmission network, except for local distribution. Further, while

the Commission explained that one way to meet the goal was to establish a 100 kV “bright line” threshold, the Commission also made clear that the “bright line” threshold would be a “first step or proxy” in determining what facilities should be included in the bulk electric system.¹⁹³ The NOPR reiterated that, in Order Nos. 743 and 743-A, the Commission held that NERC should not necessarily stop at 100 kV and should, through the development of the exception process, ensure that “critical facilities operated at less than 100 kV, and that the Regional Entities determine [which facilities] are necessary for operating the transmission network.”¹⁹⁴ The Commission clarified that the inclusion of sub-100 kV facilities should be done in an “appropriate and consistent” manner.¹⁹⁵ Finally, in the NOPR, the Commission noted that the September 2011 Blackout Report reinforced statements in Order Nos. 743 and 743-A with respect to ensuring that sub-100 kV facilities, as appropriate, are included in the bulk electric system.¹⁹⁶ The Commission further noted that the NERC proposals at issue in this rulemaking take steps to address the treatment of sub-100 kV facilities, as well as other facilities, necessary for the operation of the interconnected transmission network, through the exception process. However, in light of the September 2011 Blackout Report, the Commission requested

¹⁹³ Order No. 743-A, 134 FERC ¶ 61,210 at P 40; *see also* NOPR, 139 FERC ¶ 61,247 at P 106.

¹⁹⁴ Order No. 743, 133 FERC ¶ 61,150 at P 121.

¹⁹⁵ Order No. 743-A, 134 FERC ¶ 61,210 at P 103.

¹⁹⁶ NOPR, 139 FERC ¶ 61,247 at P 107.

comment on how the relevant entities who control and run facilities on the interconnected transmission network will seek inclusion of sub-100 kV facilities, as well as other facilities, to ensure that all facilities that are necessary for the operation of the bulk power system are designated as bulk electric system elements.¹⁹⁷

Comments

264. NERC proposes that entities can identify sub-100 kV facilities for inclusion in a variety of ways: in the course of performing planning assessments, from day-to-day operating experience, or assessment of system events that indicate facilities not identified by application of the definition are necessary for reliable operation of the interconnected transmission network. NERC further states that an entity that requests the inclusion or exclusion of a facility must provide certain technical and engineering support for its request. NERC also points out that the exception process provides for the appeal of a decision to NERC as to whether a facility is part of the bulk electric system. NERC believes this process adequately addresses the issue of whether certain sub-100 kV facilities are included in the bulk electric system.

265. ELCON states that the NOPR's suggestion that the entities would not take cognizance of Commission or NERC findings related to any sub-100 kV elements that have a material impact on system reliability would call into question the efficacy of the entire construct established by the Commission to address reliability issues.

¹⁹⁷ NOPR, 139 FERC ¶ 61,247 at PP 109-10.

266. APPA believes that it will be excessively burdensome to industry and small entities if they have to conduct a study of all their sub-100 kV elements. APPA asserts that it would require small registered entities to hire consultants to perform studies to assess the impact of large numbers of non-bulk electric system facilities.

267. Idaho Power believes that entities could periodically (e.g. every five years) review the impact of sub-100 kV facilities and verify if any of the inclusions would require them to be included and explain why certain sub-100 kV facilities are excluded.

268. ISO New England and National Grid believe that, during the conduct of transmission planning system assessments, performed in accordance with requirements of the NERC Transmission Planning Reliability Standards, facilities required for inclusion in the bulk electric system may be identified.

Commission Determination

269. As we held in Order Nos. 743 and 743-A, the goal of revising the definition of bulk electric system is to ensure that all necessary facilities are included in the bulk electric system. As we noted in Order No. 743, applying the definition of bulk electric system should be a “first step or proxy” in determining which facilities should be included in the bulk electric system.¹⁹⁸ The Commission stated that NERC should not end the inquiry at 100 kV and should, through the development of the exception process, ensure that “critical” facilities operated at less than 100 kV, and that the Regional Entities

¹⁹⁸ NOPR, 139 FERC ¶ 61,247 at P 106 (citing Order No. 743-A, 134 FERC ¶ 61,210 at P 40).

determine are necessary for operating the interconnection network are included.¹⁹⁹ We continue to expect entities to identify and include sub-100 kV facilities, as well as other facilities, necessary for the operation of the interconnected transmission network. In the NOPR we asked how the entities responsible for including elements in the bulk electric system will assure that the all facilities, including sub-100 kV elements, that are necessary for operating the interconnected transmission network will be included in the bulk electric system. We find NERC's response to that question reasonable: that Regional Entities, planning authorities, reliability coordinators, transmission operators, transmission planners, balancing authorities, and owners of system elements will include, through the exception process, facilities identified in the course of performing planning assessments, from day-to-day operating experience, or assessment of system events that are not included by application of the definition but are necessary for reliable operation of the interconnected transmission network. We believe that entities, having knowledge of their systems and the concomitant planning assessments and system impact studies, will identify an element that is necessary for reliable operation of the integrated transmission network while conducting their day-to-day operations and planning and performing studies. If the element does not fall within the definition, we expect that the entity will submit the element for inclusion through the exception process. Use of this process should ensure that the all sub-100 kV elements, as well as other facilities, necessary for

¹⁹⁹ Order No. 743, 133 FERC ¶ 61,150 at P 121.

the operation of the interconnected transmission network are included in an “appropriate and consistent” manner. By identifying and seeking inclusion of sub-100 kV facilities, and other facilities, in the bulk electric system through performance of these routine functions, such as those identified by ISO New England and National Grid, we do not expect that entities will have to perform studies indiscriminately to make such determinations. Indeed, comments indicate that the determination of which elements, including sub 100 kV elements, should be included in the bulk electric system is a natural part of an entities’ process for assuring the reliable operation of the grid.²⁰⁰ Thus, the Commission believes that, if a study is needed outside the ordinary course of operations, it would be infrequent. By adopting this approach, we believe that APPA’s concerns about burdensome tasks are alleviated.

2. NERC Role in Identifying Necessary Elements

270. In the NOPR, the Commission observed that, despite NERC’s statutory functions to develop and enforce Reliability Standards, its continent-wide perspective, and technical understanding that can provide valuable assistance in the identification of bulk electric system facilities, the exception process does not provide that NERC may initiate an exception request. Accordingly, the Commission requested comments on the role NERC should have in initiating the designation of or directing others to initiate the designation of sub-100 kV facilities, or any other facilities, necessary for the operation of

²⁰⁰ *E.g.*, ELCON Comments at 8.

the interconnected transmission network for inclusion in the bulk electric system.²⁰¹ The Commission also requested comment on the role NERC should have in designating sub-100 kV facilities, and other facilities, for inclusion in the bulk electric system, directing Regional Entities or others to conduct such reviews, or itself nominating an element to be included in the bulk electric system.

Comments

271. NERC states that inherent in its oversight of the Regional Entities is the ability to request a Regional Entity or others to propose inclusion of sub-100 kV facilities, and other facilities in the bulk electric system. NERC further states that the Rules of Procedure do not limit its ability to perform this function and such action is fully consistent with NERC's obligations and authority as the ERO.

272. Dominion believes that if NERC wants to nominate a sub-100 kV facility, it could do so through the broad powers assigned to NERC through its Rules of Procedure and/or regional delegation agreements. TAPS maintains that if, through its investigations, risk assessments, or analysis of events, NERC identifies facilities that should be included in (or excluded from) the bulk electric system, it would be appropriate for NERC to have the authority to make such a proposal through the exception process, provided that it implements due process safeguards such as the designation of decisional and non-decisional staff.

²⁰¹ NOPR, 139 FERC ¶ 61,247 at P 111.

273. Several commenters state that NERC should have the ability to nominate a facility for inclusion. SmartSenseCom believes NERC should have authority to initiate an exception request because, even with a bright line standard, there remains the possibility of inconsistent interpretation and application of the definition. ISO-NE states that NERC should have the ability to nominate a facility for inclusion, but the Regional Entities along with planning authorities, reliability coordinators, transmission operators, transmission planners and balancing authorities should be provided an opportunity to review and comment on this nomination.

274. AEP believes that RTOs or Regional Entities “are equipped to facilitate the efforts to be effective with the exception process.”²⁰² AEP also suggests that NERC and the Commission could assign review of sub-100 kV facilities to the RTOs. AEP states that the RTO processes could be modified to address the exceptions. AEP defers to the judgment of the Commission and NERC in regions where there are currently no functioning RTOs.

275. Other commenters do not support a NERC role as contemplated in the NOPR. SoCal Edison believes that NERC should not initiate exception requests to include facilities within the bulk electric system. Rather, SoCal Edison posits that NERC’s role is to communicate to the Regional Entities their obligation to review systems in their area that operate in parallel with the bulk electric system and to include such systems in the

²⁰² AEP Comments at page 11.

bulk electric system. APPA supports consideration of a NERC role in Phase 2 of the project to identify specific reliability gaps but objects to NERC being able to step into the shoes of the Regional Entity.

Commission Determination

276. NERC states that, as the ERO, and in its oversight of the Regional Entities, it has the ability to request a Regional Entity or others to propose inclusion of sub-100 kV facilities, and other facilities, in the bulk electric system. NERC believes that nothing in the proposed Rules of Procedure limits its oversight obligations and authority as the ERO. The Commission finds NERC's approach to be reasonable. Section 215(e)(4)(C) of the FPA authorizes the Commission to issue regulations authorizing the ERO to enter into an agreement to delegate authority to Regional Entities if the agreement promotes effective and efficient administration of Bulk-Power System reliability.²⁰³ Subsequently, the Commission approved delegation agreements between NERC and the eight Regional Entities.²⁰⁴ Pursuant to the delegation agreements, NERC may issue guidance or directions as to the manner in which a Regional Entity performs delegated functions and related activities.²⁰⁵ Thus, the Commission agrees with NERC that, as the ERO, NERC

²⁰³ 16 U.S.C. 824o (2006).

²⁰⁴ *North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, *order on reh'g*, 120 FERC ¶ 61,260 (2007).

²⁰⁵ *See, e.g.*, section 8(d) of the Amended and Restated Delegation Agreement between NERC and Midwest Reliability Organization (...the NERC Board (or a Board committee to which the Board has delegated authority) may issue guidance or directions

(continued...)

has the authority to request a Regional Entity or other eligible submitting entity to propose inclusion of sub-100 kV facilities, or other facilities, in the bulk electric system.

277. TAPS supports NERC having the ability to initiate the designation of facilities or elements as part of the bulk electric system, provided that NERC implements due process safeguards such as the designation of appropriate decisional and non-decisional staff. We agree that, to avoid actual or appearance of impropriety, NERC must develop appropriate safeguards.

278. In response to AEP, the Commission will not direct modifications to provide RTOs and ISOs the authority to address exception requests. RTOs and ISOs can submit exception requests in their capacity as planning authorities, reliability coordinators, transmission operators, transmission planners, and/or balancing authorities.

3. Commission Role in Identifying Necessary Elements

NOPR Proposal

279. In the NOPR, the Commission requested comment on the role the Commission should have with respect to the designation of sub-100 kV facilities, or other facilities, necessary for the operation of the interconnected transmission network for inclusion in the bulk electric system. The Commission observed that “there may be circumstances (like the September 2011 Blackout Report) where the Commission, through the performance of its statutory functions, may conclude that certain sub-100 kV facilities

as to the manner in which Midwest Reliability Organization and, if applicable, other Regional Entities, shall perform delegated functions and related activities.”).

not already included in the bulk electric system are necessary for the operation of the interconnected transmission network and thus should be included in the bulk electric system.”²⁰⁶ The Commission stated that it expected that Regional Entities and others “will take affirmative steps to review and include sub-100 kV elements and facilities, and other facilities, necessary for the operation of the interconnected transmission system in the bulk electric system,” and requested comment as to how the Commission could ensure that such facilities are considered for inclusion in the bulk electric system.²⁰⁷ The Commission also requested comment on instances when the Commission itself should designate or direct others to designate sub-100 kV facilities, or other facilities, necessary for the operation of the interconnected transmission grid for inclusion in the bulk electric system.

Comments

280. NERC notes that the Commission has authority pursuant to FPA section 215(d)(5) to initiate a Reliability Standards development process that “addresses a specific matter.” According to NERC, for the Commission to play a more active role in the designation of such facilities would be inconsistent with its role as the adjudicator of disputes.

²⁰⁶ NOPR, 139 FERC ¶ 61,247 at P 112.

²⁰⁷ NOPR, 139 FERC ¶ 61,247 at P 112.

281. Some commenters assert that the Commission has the authority to designate a facility as part of the bulk electric system.²⁰⁸ SmartSenseCom states that, if the Commission is concerned that a facility is necessary for the operation of the interconnected transmission system, it possesses authority to order NERC or a Regional Entity to address that matter. Specifically, SmartSenseCom points to section 215(b) and section 215(d)(5) where the Commission has plenary authority over the ERO and “all users, owners, and operators of the bulk-power system” for the purposes of approving reliability standards and enforcing compliance with those standards.²⁰⁹ SmartSenseCom states that, pursuant to the statutory authority, the Commission could, on its own motion, “order [NERC] to submit... a modification to a reliability standard that addresses a specific matter if the Commission considers such...modified reliability standard appropriate to carry out this section.”²¹⁰

282. Furthermore, SmartSenseCom states that the Commission should be able to review NERC exceptions decisions. SmartSenseCom asserts that NERC decisions should be subject to the discretionary review of the Commission and the Commission should retain the ability to remand or reject an exception determination, pursuant to the Commission’s FPA section 215 statutory authority to approve, disapprove, or remand NERC-proposed

²⁰⁸ *E.g.*, Dominion and SmartSenseCom.

²⁰⁹ SmartSenseCom Comments at 14, *quoting* 16 U.S.C. 824o(b).

²¹⁰ *Id.* at 14, *quoting* 16 U.S.C. 824o(d)(5).

Reliability Standards. While the Commission should give NERC's exception decision "due weight" as required by section 215, SmartSenseCom asserts that the availability of review would ensure reliable operation of existing and future Bulk-Power System facilities. SmartSenseCom also suggests that Commission review of exception decisions would provide industry stakeholders with valuable precedent and clarity on the treatment of certain facilities.

283. Other commenters claim that the Commission does not possess the authority to designate elements as part of the bulk electric system. ISO New England contends that the Commission, as the ultimate decision making authority, should not have a role in nominating facilities for inclusion in the bulk electric system. APPA does not believe that the FPA gives the Commission authority to designate specific elements for inclusion in the bulk electric system. Rather, according to APPA, the Commission's role is to review NERC decisions. APPA states that policy considerations and Congressional intent also "militate against direct [Commission] identification of specific facilities or classes of facilities to be included in the [bulk electric system] definition."²¹¹ APPA asserts that, during the course of a Part 1b investigation or other inquiry, the Commission may identify facts that indicate that a registered entity has not properly applied the definition. APPA points to FPA section 215(e)(3) which provides that, after notice and opportunity for hearing, the Commission may enforce compliance by a particular user,

²¹¹ APPA Comments at 20.

owner or operator of the Bulk-Power System with a Reliability Standard, which could include application of the definition within the context of a specific reliability standard. APPA argues, that section 215 contemplates a standard development and enforcement framework in which rules of general applicability, i.e., Reliability Standards, are developed by the ERO on a continent-wide, and are subject to Commission approval prior to the enforcement of such Reliability Standards. In contrast, APPA argues that section 215 contemplates the delegation of enforcement authority by the ERO to Regional Entities that are organized to accomplish this specific purpose. APPA concludes that the Commission, like NERC, should focus its resources on ensuring that Regional Entities enforce compliance with the definition and the Rules of Procedure.

284. SoCal Edison does not support active Commission involvement in designating facilities for inclusion in the bulk electric system. According to SoCal Edison, because the Commission has the authority to review NERC's decisions in the exceptions procedure, the Commission's role should be limited to providing to NERC information that the Commission develops on facility categories that should potentially be included in the bulk electric system. Further, SoCal Edison states that NERC should be responsible for communicating that information to Regional Entities for further action and ensuring that those Regional Entities take the appropriate action with respect to such information, and the Commission should ensure that NERC and the regional authorities act upon the information provided by the Commission with respect to such facilities.

Commission Determination

285. For the reasons discussed below, we conclude that the Commission has the authority to designate an element as part of the bulk electric system pursuant to our authority set forth in sections 215(a)(1) and (b)(1) of the FPA. We are cognizant of the concerns stated by SoCal Edison and other commenters regarding the appellate role of the Commission, and the desire to allow registered entities and Regional Entities to take the lead in identifying sub-100 kV elements, and other elements, that should be included in the bulk electric system. As explained above, we expect entities to identify and include sub-100 kV elements, and other elements, that are necessary for operating the interconnected transmission network in the bulk electric system. Nonetheless, we believe that in appropriate circumstances, for example, where an event analysis of a system disturbance indicates the operational importance of sub-100 kV elements, and other elements, to bulk electric system reliability, the Commission may find it necessary for the reliable operation of the interconnected transmission network to designate facilities to be included in the bulk electric system. We anticipate that such circumstances will be rare. Consistent with the approach discussed in the NOPR, the Commission would provide public notice and opportunity for public comment before designating facilities as part of the bulk electric system.²¹²

²¹² NOPR, 139 FERC ¶ 61,247 at P 112, n.127.

286. Commenters are mistaken in characterizing the Commission’s designation of facilities as bulk electric system as a modification to the bulk electric system definition or other Reliability Standard. Rather, our authority to designate facilities is based on the statutory definition of Bulk-Power System and the jurisdictional authority vested in the Commission pursuant to section 215 of the FPA. Specifically, section 215(b)(1) of the FPA provides that “the Commission shall have jurisdiction, within the United States, over...all users, owners and operators of the bulk-power system...for purposes of approving Reliability Standards established under this section and enforcing compliance with this section.”²¹³ Section 215(a)(1) of the FPA, in turn, defines “Bulk-Power System” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and electric energy from generation facilities needed to maintain transmission system reliability.”²¹⁴ If an entity owns or operates sub-100 kV elements, or other elements, “necessary for operating an interconnected electric energy transmission network,” the Commission has jurisdiction pursuant to FPA section 215(b)(1) to “enforc[e] compliance with this section,” and to ensure that the approved definition is being implemented properly.

287. For example, an entity may operate sub-100 kV elements, or other elements, that are, pursuant to the modified definition approved in this Final Rule, not treated as part of

²¹³ 16 U.S.C. 824o(b)(1).

²¹⁴ 16 U.S.C. 824o(a)(1).

the bulk electric system. However, an event analysis may reveal that such facilities are “necessary for operating an interconnected electric energy transmission network.” As an appropriate prospective remedy, pursuant to the FPA section 215(b)(1) authority to “enforc[e] compliance with this section,” the Commission could designate the facilities as part of the bulk electric system. This approach is consistent with Commission precedent regarding unregistered entities whose facilities are involved in a violation of Reliability Standards. The Commission determined that, in such situations, the appropriate remedy is to register the entity so that, prospectively, the entity must comply with the relevant Reliability Standards based on the functions performed by that entity.²¹⁵

288. The Commission would not modify the language of the definition of bulk electric system or the specific inclusions and exclusions. Rather, the Commission would initiate the designation of elements to ensure that the definition is properly applied. To be clear, when, for example, a system disturbance or other event demonstrates the necessity of sub-100 kV elements, or other elements, for reliable operations, we expect in the normal course that registered entities, Regional Entities and NERC will proactively identify and include sub-100 kV elements, or other elements, in the bulk electric system. The Commission’s strong preference is that registered entities review their facilities to determine which are needed for operating the interconnected transmission network and

²¹⁵ See *Reliability Standard Compliance and Enforcement in Regions with Regional Transmission Organizations or Independent System Operators*, 122 FERC ¶ 61,247, at P 19 (2008).

include them in the bulk electric system. However, when it is recognized that an element is necessary for the operation of the interconnected transmission network and no other entity steps forward to designate the element as included in the bulk electric system for purposes of section 215, the Commission has the authority to do so. We anticipate that such instances will be rare. Should the Commission find it necessary and appropriate to exercise this authority, we anticipate that the Commission would, for example, issue either a notice or order proposing to designate a specific element or elements as part of the bulk electric system, and explain the rationale for the proposal. The Commission would make a final determination after providing notice and opportunity for comment by interested parties.

4. Technical Review Panel

NOPR Proposal

289. NERC's exception process provides that the Regional Entity shall not recommend disapproval of the exception request without review by a technical review panel. The Regional Entity is not bound by the opinion of the panel, but the panel's evaluation becomes part of the record associated with the exception request and provided to NERC. In the NOPR, the Commission stated that it saw value in the Regional Entity receiving the opinion of a qualified technical review panel. The Commission observed that NERC did not explain why the proposed exception process only requires a technical review panel to provide an opinion where the Regional Entity recommends disapproval of an exception request. Accordingly, the Commission requested comment from NERC explaining why the review is only required when a Regional Entity disapproves a request

and whether NERC should modify the exception process to require Regional Entities to submit all proposed determinations to a technical review panel regardless of the recommendation and receive the panel's opinion on each request.

Comments

290. NERC stated that it considered obtaining the opinion of a technical panel for all Regional Entity recommendations; however, NERC concluded that a review should only be required when a Regional Entity disapproves a request due to concerns regarding administrative efficiency. NERC determined that negative technical reviews would be sufficient to promote consistency and that the additional costs and work of a review of all proposed determinations would outweigh the benefits. NERC further states the record of every request is reviewed by a panel of experts at the NERC level as part of the decision making process.

291. Several entities support NERC's explanation.²¹⁶ ELCON believes NERC's approach will avoid the burden, inefficiency and delay inherent in unnecessary referrals to a technical review panel. ELCON notes that the exception process already calls for submission of in-depth technical information through the Detailed Information Form, initial review by the Regional Entity, and subsequent review and final decision by NERC. ELCON believes that considerable technical expertise will, therefore, be available to both the Regional Entity and to NERC as they assess exception requests.

²¹⁶ *E.g.*, Idaho Power, ELCON, and G&T Cooperatives.

292. In contrast, some entities believe that a technical panel be convened for either approval or denial of all exceptions.²¹⁷ They believe that using a panel for all requests will ensure that the requests receive adequate consideration and vetting before a final decision is rendered. WPPC requests that the Commission obtain additional information from NERC with respect to why the Technical Review Panels are not required to review all exception requests that are rejected on procedural grounds.

Commission Determination

293. The Commission accepts NERC's explanation that requiring a technical panel review of all Regional Entity recommendations will likely cause an additional administrative burden on Regional Entities, delaying final recommendations to NERC. While the Commission sees benefits in utilizing a technical review panel for all requests, we are not persuaded that these benefits will outweigh the costs associated with the increased administrative burden likely to be imposed. Additionally, if the Technical Review Panel does not provide an opinion on all exception requests, the exception process is not without other levels of technical review. On the contrary, the exceptions process provides multiple levels of technical review before a final determination is made by NERC, including a substantive review by the Regional Entity and a subsequent review by a panel of technical experts at the NERC level. For these reasons, the Commission approves the Technical Review Panel as proposed by NERC.

²¹⁷ *E.g.*, ISO New England and BPA.

294. In response to WPPC's request, the Commission declines to seek further information from NERC with respect to why the Technical Review Panels are not required to review all exception requests that are rejected on procedural grounds. Section 5.1.5(a) of Appendix 5C to the Rules of Procedure requires a Regional Entity to reject an exception request if it is not from an eligible submitting entity and/or it does not contain all the required information specified in section 4.0. The Commission does not believe a Technical Review Panel needs to determine if an exception request was properly submitted by an eligible entity and/or contains all the required information. Additionally, as WPPC states in its comments, submitting entities may appeal Regional Entity rejections of exception requests to NERC through the procedure provided in section 7.0 of the exception process. Requiring Technical Review Panel review of all rejections of exception requests, as well as all recommendations of disapprovals, would unnecessarily impose administrative burdens as if the Technical Review Panel was required to review all exception request recommendations. For these reasons, the Commission declines WPPC's request to obtain further information from NERC on this matter.

5. Use of Industry Subject Matter Experts

NOPR Proposal

295. Section 8 of the proposed exception process sets forth the procedures for NERC's review of a Regional Entity's recommendation. The NERC President will appoint a team of at least three persons with the relevant technical background to evaluate an exception request. NERC contemplated that its review teams would be drawn from NERC staff resources, supplemented by contractors as necessary, but situations may arise in which

NERC may need to call on industry subject matter experts to participate as members of review teams. In the NOPR the Commission supported NERC's proposal to use staff resources, supplemented by contractors as necessary, to make up the exception request review teams. We stated that consistent appointment of the same NERC staff and contractor resources, based on subject matter expertise, will promote a more uniform and consistent review of the Regional Entities' exception request recommendations.

Comments

296. No comments were received on this issue.

Commission Determination

297. The Commission agrees with NERC's proposal to use staff resources, supplemented by contractors as necessary, and potentially industry subject matter experts to make up the exception request review teams. The Commission believes that ensuring that members of the NERC review teams have the required technical background necessary to evaluate exception requests, review supporting technical documents, and assess technical recommendations, is essential to providing consistent technically sound determinations on exception requests. The Commission believes that consistent appointment of the same NERC staff, contractor resources and industry subject matter experts, based on subject matter expertise, will promote a more uniform and consistent review of the Regional Entities' exception request recommendations.

6. NERC's Detailed Information Form

NOPR Proposal

298. NERC developed the Detailed Information Form that the Regional Entity and NERC can use in evaluating whether or not the elements that are the subject of an exception request are necessary for operating the interconnected transmission network. In the NOPR, the Commission stated that this information will provide consistency with respect to the technical information provided with all exception requests and is an equally efficient and effective approach to developing a substantive set of technical criteria for granting and rejecting exception requests and proposed to approve the Detailed Information Form.

Comments

299. ELCON supports the Detailed Information Form and agrees that it is “more feasible to develop a common set of data and information that could be used by the Regional Entities and NERC to evaluate exception requests” than to develop the detailed criteria and that the information specified in the form is relevant and appropriate for exception requests.

300. Holland and Alameda state that there should be some basic guidelines to evaluate an exception request. Alameda states that having no technical criteria provides entities with no guidance considering a request for exception. Alameda submits that parties should have a reasonable basis for determining the outcome of a potential exception request in advance of taking the time and effort to make the request. Alameda suggests that the Commission direct NERC to develop appropriate technical exception criteria,

recognizing that each criterion may not apply to all requests and that the criterion may even change over time as specific requests are evaluated in detail. Alameda also seeks clarification that parties may seek exceptions for proposed facilities, and not just for existing facilities as allowing exceptions to be requested for proposed facilities would provide an opportunity for entities to make reasoned decisions about planned system improvements.

Commission Determination

301. We approve the Detailed Information Form and find that it will provide consistency with respect to the technical information provided with all exception requests and is an equally efficient and effective approach to developing a substantive set of technical criteria for granting and rejecting exception requests. We decline to adopt Alameda's suggestion that the Commission direct NERC to develop appropriate technical exception criteria. We accept NERC's conclusion that it was more feasible to develop a common set of data and information that could be used by the Regional Entities and NERC to evaluate exception requests than to develop the detailed criteria. NERC's proposal provides the needed flexibility to allow Regional Entities to make a recommendation of whether or not an element is necessary for the reliable operation of the interconnected transmission network. Thus, the detailed criteria that NERC requires, plus other information that an entity is free to include in its submission will provide applicants a reasonable basis for determining whether an element is necessary for the reliable operation of the interconnected transmission network. We also decline to direct NERC to determine how to treat exceptions for proposed facilities.

7. NERC's Implementation Plan

NOPR Proposal

302. NERC requests that the effective date for revised definition should be the first day of the second calendar quarter after receiving applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, the revised bulk electric system definition should go into effect on the first day of the second calendar quarter after its adoption by the NERC Board. NERC also requested that compliance obligations for all newly-identified elements to be included in the bulk electric system based on the revised definition should begin twenty-four months after the applicable effective date of the revised definition. NERC stated that sufficient time is needed to implement transition plans, for exceptions to be filed and processed, for owners of newly-included elements to train their personnel on compliance with the Reliability Standards. In the NOPR, the Commission supported NERC's justification for its implementation and proposed to approve NERC's implementation plan.

Comments

303. A number of commenters support the NOPR proposal.²¹⁸ ELCON states that the twenty-four month time period gives sufficient time to accommodate planning for and changes resulting from the new definition, including any exception requests and compliance obligations, without causing undue delay. Consumers believes the twenty-

²¹⁸ *E.g.*, Consumers Energy, ELCON, and NYISO.

four month period should be sufficient in most cases but believes that the Commission should make specific provision for longer periods to be allowed on a case-by-case basis under special circumstances. Barrick and IUU also support the implementation plan but believe further clarification is necessary with respect to an entity's status during the exception process.

Commission Determination

304. We agree with commenters that the twenty-four month time period gives sufficient time to accommodate planning for and changes resulting from the new definition, including any exception requests and compliance obligations. Therefore, we approve NERC's proposal to implement a twenty-four month implementation plan. In response to Consumers' comment regarding the need for additional time for special circumstances, an entity or NERC may petition for an extension of time. In response to the comments raised by Barrick and IUU, we clarify that the status of an element remains unchanged during the exception process.

8. NERC List of Facilities Granted Exceptions

NOPR Proposal

305. In the NOPR, the Commission noted that the proposed exception process does not include provisions for NERC to maintain a list of facilities that have received exceptions, as requested in Order No. 743. In its petition, NERC indicated that this is an internal administrative matter for NERC to implement that does not need to be embedded in the Rules of Procedure. NERC stated it will develop a specific internal plan and procedures for maintaining a list of facilities for which exceptions have been granted and notes that

Regional Entities will maintain lists of elements within their regions for which exceptions have been granted, in order to monitor compliance with the requirement to submit periodic certifications.

306. In the NOPR, the Commission proposed that NERC make an informational filing within 90 days of the effective date of a final rule, detailing its plans to maintain a list and how it will make this information available to the Commission, Regional Entities, and potentially to other interested persons.²¹⁹ The Commission also requested comment on whether NERC's proposal should be modified to include an obligation for the registered entity to inform NERC or the Regional Entity of the entity's self-determination through application of the definition and specific exclusions E1 through E4 that an element is no longer part of the bulk electric system.

Comments

307. NERC confirms that it is continuing to develop details regarding how the list of facilities that have received exceptions will be maintained. According to NERC, a 90-day window of time in which to submit an informational filing is reasonable.

308. Other entities support NERC's plan.²²⁰ AEP cautions that the process of submitting a filing must not overstep the confidentiality provisions of Critical Energy Infrastructure Information as part of the gathering and dissemination of list(s).

²¹⁹ NOPR, 139 FERC ¶ 61,247 at P 123.

²²⁰ ELCON and NRECA.

309. The Massachusetts DPU supports NERC's keeping a list of exceptions and requests that the Commission requires that state regulatory authorities have appropriate access to the list. ISO New England proposes that NERC submit a compliance filing detailing its internal process for tracking exception requests. ISO New England also believes that NERC and/or the Regional Entities should be required to maintain a database that lists the bulk electric system elements within their respective footprints and should make this data available for affected entities.

Commission Determination

310. We adopt the NOPR proposal and direct NERC to make an informational filing within 90 days of the effective date of this Final Rule detailing its plans to maintain a list and how it will make this information available to the Commission, Regional Entities, and potentially to other interested persons. We find that the suggestions of the Massachusetts DPU and ISO New England are premature as these comments are more appropriate for consideration after NERC makes its compliance filing.

9. Declassification of Facilities

NOPR Proposal

311. In the NOPR, the Commission observed that, while NERC will maintain a list of facilities that have received an exception pursuant to the case-specific exception process, NERC does indicate whether it will track an entity's "declassification" of current bulk electric system facilities based on the entity's self-application of the bulk electric system

definition.²²¹ The Commission expressed concern particularly when an entity self-determines that an element is no longer part of the bulk electric system but the entity is large enough to otherwise remain on the NERC Compliance Registry. Accordingly, the Commission requested comment on whether NERC's proposal should be modified to include an obligation for the registered entity to inform NERC or the Regional Entity of the entity's self-determination through application of the definition and specific exclusions E1 through E4 that an element is no longer part of the bulk electric system.

Comments

312. NERC asserts that registered entities are obligated to inform the Regional Entity of any self-determination that an element is no longer part of the bulk electric system.

NERC points to section 501 of the currently-effective Rules of Procedure, which provides that each registered entity must notify its Regional Entity of any matters that affect the registered entities' responsibilities with respect to Reliability Standards. NERC contends that a determination that an element is no longer part of the bulk electric system would necessarily affect an entity's responsibilities with respect to the Reliability Standards. Further, NERC states that an entity's failure to notify would not relieve it of any obligations it may have associated with such failure.

313. Idaho Power and National Grid support that registered entities should inform NERC or the Regional Entity of elements that have been declassified. National Grid

²²¹ NOPR, 139 FERC ¶ 61,247 at P 123.

supports an obligation for each registered entity to inform the respective reliability coordinators and Regional Entity of the entity's self-determination through application of the definition and specific exclusions that an element is no longer part of the bulk electric system.

314. PSEG Companies do not support requiring self reporting. PSEG Companies point out that when the NERC Functional Model was first put in place, registered entities made determinations of which facilities should be included and excluded from the bulk electric system without any reporting requirements for those decisions. PSEG Companies assert that a registered entity should only be contacting its Regional Entity regarding status changes if those changes impact the registered entity's registration (e.g., if a registered Transmission Owner disposes of all its 100 kV or higher assets or a generation owner acquires its first BES generator). According to PSEG Companies, facility changes that impact a facility's bulk electric system status do not presently require reporting. The proposed reporting self-determined exclusions could lead to extensive facility-by-facility tracking and reporting of all status changes which would be overly burdensome to Registered Entities.

315. AEP believes that it is imperative to keep the process simple in the beginning, and thus advocates that no specific information submission requirements be implemented at this time. If NERC or the Regional Entities determine this approach is problematic in the future, AEP states that any issues can be addressed through a change in the NERC Rules of Procedure.

316. ICNU states that if NERC requires an end-use retail customer to provide notice of declassification, such notice should not involve extensive or burdensome reporting requirements because, as noted above, end-use customers do not have the required resources or expertise. On the other hand, ICNU believes that non-registered end-use retail customers who, based on the new BES definition, determine that they remain excluded from the BES should not be listed or required to report such determination to NERC or the appropriate Regional Entity.

Commission Determination

317. We agree with NERC that registered entities are obligated to inform the Regional Entity of any self-determination that an element is no longer part of the bulk electric system. PSEG Companies claim that there is currently no requirement to report the change in status of facilities. NERC, however, cites section 501 of the currently-effective Rules of Procedure, which provides that each registered entity must notify its Regional Entity of any matters that affect the registered entities' responsibilities with respect to Reliability Standards. Section 501 also requires entities to inform the Regional Entity of any self-determination that an element is no longer part of the bulk electric system.

Section 501, Part 1.3.5 provides:

Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or

shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

Thus, a registered entity that concludes that an element is no longer part of the bulk electric system must notify the Regional Entity of such change. Further, we disagree with PSEG Companies that such notification is unnecessary. PSEG Companies point out that NERC did not require such notification when the Functional Model was first put into place. Regardless of past practice, we find that such notification is a necessary feature of the changes being implemented by NERC. As explained in the NOPR:

a large utility with hundreds or thousands of transmission lines may initially determine that a configuration on its system does not qualify for the exclusion E3 local network exclusion, but subsequently determines that the configuration can be excluded. NERC's petition does not indicate whether an entity in such circumstance is obligated to inform NERC or the appropriate Regional Entity of that self-determination. It appears that NERC and the Regional Entities would need this information for their compliance programs, for audit purposes, and to understand the contours of the bulk electric system within a particular region.

Further, the revised definition allows entities the discretion to "declassify" certain facilities as part of the bulk electric system, and NERC, Regional Entities and the Commission need notification of such instances to assure that the entities are appropriately implementing the revised definition.

318. We affirm ICNU's assertion that this task does not involve new, extensive or burdensome reporting requirements. We view this as an identification and notification task so that a Regional Entity and NERC will know what elements are or not part of the

bulk electric system. This will provide the entities tasked with overseeing the reliable operation of the interconnected transmission network with having an adequate level of information and transparency to fulfill those obligations. We disagree with PSEG Companies that this is an overly burdensome requirement. First, such information sharing is already contemplated by the Rules of Procedure. Second, as noted above, we do not view this requirement as one that involves anything more than notification. It does not require a justification of why the element is being excluded.

III. Information Collection Statement

319. The Office of Management and Budget (OMB) requires that OMB approve certain information collection and data retention requirements imposed by agency rules.²²² 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.

Public Reporting Burden and Information Collection Costs

320. In the NOPR, the Commission solicited comment on the need for collecting the information that is required to be prepared, maintained and/or submitted pursuant to this Final Rule, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden,

²²² 5 CFR 1320.11 (2011).

including the use of automated information techniques. The NOPR also included a chart that identified the estimated public reporting burdens for the proposed reporting requirements, as well as a projection of the costs of compliance for the reporting requirements. The Commission asked that any revised burden estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated. The Commission based its burden estimate on the revised definition of bulk electric system developed by NERC.

321. In the NOPR, the Commission stated that the proposal would result in entities reviewing systems and creating qualified asset lists, submitting exception requests where appropriate, and certain responsible entities having to comply with requirements to collect and maintain information in mandatory Reliability Standards with respect to certain facilities for the first time. The Commission requested comment on the estimated number of entities that will have an increased reporting burden associated with the identification of new bulk electric system elements as a result of the modified definition. In developing an estimate of the reporting burden associated with the inclusion of additional elements, like NERC, the Commission assumed that entities in the NPCC Region will be most affected, with a lesser affect in other regions.

Comments

322. NRECA and APPA do not take a position on the estimates but observe that modifications to the proposed definition or directives to NERC may result in substantial changes to the burden estimates and the assessment of whether the which would require the Commission to re-assess its burden and small business impact determinations.

Similarly, APPA and WPPC believe that any changes to the proposed definition in the Final Rule that would include additional facilities would cause a significant increase in the reporting burden on the industry. APPA believes that if the Commission were to direct NERC to make revisions to the specific inclusions or exclusions without technical justification, the exception process would quickly become overloaded, with burdens on those seeking exceptions and those ruling on them.

323. A number of commenters state that the NOPR underestimated the burden of the rulemaking in terms of hours required to comply. APPA believes that the Commission underestimates the information collection costs and the costs of compliance for small utilities. For example, the Commission's assumption that utility staff would be used to conduct an analysis is not merited in the case of many small entities. APPA states that many of its smaller members do not have the in-house employees and resources to conduct such reliability analyses and would have to rely on outside consultants and legal firms. Therefore, APPA estimates that the fees small utilities would pay for each of the services, based on information and belief, as follows: Consulting Engineer, \$225/hour; Record Keeping, \$75/hour; and Legal, \$500/hour.

324. Idaho Power contemplates five local network exclusions which contain sixty 100 kV and above lines, and its estimates for the time involved to document these exceptions leads it to believe the Commission is underestimating the number of engineer hours per entity's responses. According to Idaho Power, based on an initial review of potential exceptions, Idaho Power may seek approximately 9-12 exceptions. Idaho Power agrees with the estimate that transmission owners, generator owners, and

distribution providers will experience more significant reporting burdens than other categories of registered entities.

325. ISO New England believes that there could be a significant burden on planning coordinators and transmission planners which is not addressed in the table shown in the NOPR. ISO New England states that, while it has not performed a similar analysis, it appears that the “Year 1” estimates in the table in the NOPR are significantly understated in view of the resources that it believes will be necessary to establish the initial list. According to ISO New England, the estimate of approximately \$13 million expended over the entire system seems overly optimistic. BPA anticipates, based on customer feedback, that the BPA footprint alone will experience several hundred exception requests in the first two years. BPA estimates the additional workload from evaluating the exception requests will be approximately five to six full time equivalents which includes one full time coordinator, a customer service engineer for system verification, a planner to run studies, an operations engineer, and dispatch personnel for real-time system impacts. NYPSC and the Massachusetts DPU contend that the costs of compliance with the definition will be excessive. NYPSC cites to a 2009 report from NERC and NPCC, that the compliance costs would exceed \$280 million.

Commission Determination

326. Commenters raise concerns that modifications to the proposed definition or directives to NERC may result in substantial changes to the burden estimates. While the Commission is requiring one modification to the language in the NERC proposal, the Commission finds that it does not need to reassess the burden estimates because the

change is intended to simply make more explicit what NERC and other commenters indicate is the expected application of the proposed definition to a low-voltage, looped system as depicted in figures 3 and 5 above. Therefore, we do not anticipate the one modification to result in a significant change to what elements are considered part of the bulk electric system or applications for case-by-case exceptions. The burden estimates in this Final Rule represent the incremental burden changes related only to increased reporting burden associated with the identification of new bulk electric system elements as a result of the modified definition. Furthermore, we acknowledge that NPCC may be subject to additional reporting requirements, however, the burden estimates are averages for all of the filers. Idaho Power's observation that the Commission is underestimating the number of engineering hours is not supported by analysis. Similarly, we are not persuaded by ISO New England's position that there may be a significant burden on planning coordinators and transmission planners associated with proposed definition because it does not offer any analysis to support this assertion. The Commission expects any burden for planning coordinators and transmission planners to be *de minimis* or incorporated under their existing responsibilities. In any event, Idaho Power and ISO New England did not provide any estimates of the number of hours that it would take to determine exceptions, nor suggest alternative estimates. In response to APPA's hourly estimates that are higher than the estimates in the NOPR the Commission notes that its hourly rate estimates for the burden estimates are averages for all of the filers and are based on national wage data for utilities obtained from the Bureau of Labor Statistics (for engineers and legal) and NPCC's assessment of Bulk Electric System Definition (for

completing implementation plans and compliance), and Commission staff outreach (recordkeeping). Thus, the Commission adopts the burden estimates that it set forth in the NOPR.

327. The Commission disagrees with BPA that there may be a large number of exception requests generated from entities within its footprint that may have to be processed and the significant addition of FTEs. First, BPA has not provided any analysis or evidence to support its claim. Nevertheless, the Commission's expectation, like NERC's, is that application of the definition with its inclusions and exclusions should not materially change what is considered part of the bulk electric system today. Thus, the number of exception requests should not be excessive.

328. Some comments address the potential impact the requirements would have on small entities but did not provide specific estimates on this impact. Because these comments are also the subject of the analysis performed under the Regulatory Flexibility Act, the Commission has provided a response under that section of this rulemaking.

329. We are not persuaded by NYPSC and Massachusetts DPU that the costs for compliance will be \$280 million. First, NYPSC nor Massachusetts do not dispute or address the specific information collection cost estimates in the NOPR. In addition, the vast majority (approximately \$234 million) of the costs included in the report to which the commenters cite appear to be capital costs which are not applicable to an information collection estimate. Further, the report does not account for the revised language in the definition of bulk electric system and the specific inclusions and exclusions that we are approving in this Final Rule.

330. After consideration of comments, the Commission adopts the NOPR proposal for the Public Reporting Burden and the information collection costs as follows.

Requirement	Number and Type of Entity²²³ (1)	Number of Responses Per Entity (2)	Average Number of Hours per Response (3)	Total Burden Hours (1)*(2)*(3)
System Review and List Creation²²⁴	333 Transmission Owners	1 response	80 (engineer hours)	26,640 Yr 1
	843 Generator Owners		16 (engineer hours)	13,488 Yr 1
	554 Distribution Providers		24 (engineer hours)	13,296 Yr 1
Exception Requests²²⁵	1,730 total Transmission Owners,	.260 responses each in Yrs 1 and 2	94 (60 engineer hrs, 32 record)	24,393 hrs in Yrs 1 and 2

²²³ The “entities” listed in this table are describing a role a company is registered for in the NERC registry. For example, a single company may be registered as a transmission owner and generator owner. The total number of companies applicable to this rule is 1,522, based on the NERC registry. The total number of estimated roles is 1,730.

²²⁴ This requirement corresponds to Step 1 of NERC’s proposed transition plan, which requires each U.S. asset owner to apply the revised bulk electric system definition to all elements to determine if those elements are included in the bulk electric system pursuant to the revised definition. See NERC BES Petition at 38.

²²⁵ We recognize that not all 1,730 transmission owners, generator owners, and distribution providers will submit an exception request. Rather, from the total 1,730 entities, we estimate an average of 260 requests per year in the first two years, based on a low to high range of 87 to 433 requests per year. Therefore, the estimated total number of hours per year for years 1 and 2, using an average of 260 requests per year, is 24,393 hours. We estimate 20 requests per year in year 3 and ongoing.

	Generator Owners and Distribution Providers	20 responses in Yr 3 and ongoing	keeping hrs, 2 legal hrs)	1,880 hrs in Yr 3 and ongoing
Regional and ERO Handling of Exception Requests ²²⁶	NERC and 8 Regional Entities	1 response	1,386.67 hrs	12,480 hrs in Yrs 1 and 2
Implementation Plans and Compliance ²²⁷	111 NPCC Region Registered Entities ²²⁸	1 response	700 hrs in Yrs 1 and 2	77,700 hrs in Yrs 1 and 2
			350 hrs in Yr 3 and ongoing	38,850 hrs in Yr 3 and ongoing
	75 Registered Entities from 7 other Regions	1 response	700 hrs in Yrs 1 and 2	52,500 hrs in Yrs 1 and 2
			350 hrs in Yr 3 and ongoing	26,250 hrs in Yr 3 and ongoing
TOTALS				220,497 hrs in Yr 1
				167,073 hrs in Yr 2
				66,980 hrs in Yr 3 and ongoing

²²⁶ Based on the assumption of two full-time equivalent employees added to NERC staff and 0.5 full-time equivalent employees added to each region's staff, each full-time equivalent at \$120,000/year (salary + benefits).

²²⁷ The Commission does not expect a significant number of registered entities outside of the NPCC region to identify new elements under the revised bulk electric system definition. NERC also states that the other Regional Entities do not expect an extensive amount of newly-included facilities. *See* NERC BES Petition at 38. "Compliance" refers to entities with new elements under the new bulk electric system definition required to comply with the data collection and retention requirements in certain Reliability Standards that they did not previously have to comply with.

²²⁸ The estimated range of affected NPCC Region Registered Entities is from 66 to 155 entities.

Costs to Comply:

- Year 1: **\$13,641,200**
- Year 2: **\$10,435,760**
- Year 3 and ongoing: **\$4,343,520.**

For the first two burden categories above, the loaded (salary plus benefits) costs are: \$60/hour for an engineer; \$27/hour for recordkeeping; and \$106/hour for legal. The breakdown of cost by item and year follows:

- **System Review and List Creation (year 1 only):** $(26,640 \text{ hrs} + 13,488 \text{ hrs} + 13,296 \text{ hrs}) = 53,424 \text{ hrs} * 60/\text{hr} = \$3,205,440.$
- **Exception Requests (years 1 and 2):** $(\text{sum of hourly expense per request} * \text{number of exception requests}) = ((60 \text{ hrs} * \$60/\text{hr}) + (32 \text{ hrs} * \$27/\text{hr}) + (2 \text{ hrs} * \$106/\text{hr})) * 260 \text{ requests} = \$1,215,760.$
- **Exception Requests (year 3):** $(\text{sum of hourly expense per request} * \text{number of exception requests}) = ((60 \text{ hrs} * \$60/\text{hr}) + (32 \text{ hrs} * \$27/\text{hr}) + (2 \text{ hrs} * \$106/\text{hr})) * 20 \text{ requests} = \$93,520.$
- **Regional and ERO handling of Exception Requests:** Between NERC and Regional Entities we estimate 6 full time equivalent (FTE) engineers will be added at an annual cost of \$120,000/FTE $(\$120,000/\text{FTE} * 6 \text{ FTE} = \$720,000).$ This cost is only expected in years 1 and 2.

- **Implementation Plans and Compliance²²⁹ (years 1 and 2):** (hourly expense per entity * hours per response * sum of NPCC and non-NPCC entities) = (\$64/hour * 700 hours per response * 186 responses) = \$8,332,800.
- **Implementation Plans and Compliance (year 3 and beyond):** We estimate the ongoing cost for year 3 and beyond, at 50% of the year 1 and 2 costs, to be \$4,166,400.

Title: FERC-725-J “Definition of the Bulk Electric System”²³⁰

Action: Proposed Collection of Information

OMB Control No: 1902-0259

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses: On Occasion

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

²²⁹ The cost and hourly burden calculations for this category are based on a past assessment (NPCC Assessment of Bulk Electric System Definition, September 14, 2009.). In that assessment NPCC indicated \$8.9 million annually for operations, maintenance and additional costs. We estimated that roughly half of that cost actually relates to information collection burden. Using the resulting figure, we used a composite wage and benefit figure of \$64/hour to estimate the hourly burden figures presented in the burden table.

²³⁰ All of the information collection requirements for years 1-3 in the proposed rule are being accounted for under the new collection FERC-725J.

of the nation's Bulk-Power System. Specifically, the revised definition ensures that certain facilities needed for the operation of the nation's bulk electric system are subject to mandatory and enforceable Reliability Standards.

Internal review: The Commission has reviewed the proposed definition and made a determination that its action is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimate associated with the information requirements.

331. 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].

332. For submitting comments concerning the collection of information and the associated burden estimate, please send your comments to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4718, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oir_submission@omb.eop.gov. Comments submitted to OMB should include Docket Number RM12-6 and OMB Control Number 1902-0259.

IV. Regulatory Flexibility Act Analysis

333. The Regulatory Flexibility Act of 1980 (RFA)²³¹ generally requires a description and analysis of Proposed Rules that will have a significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.²³² The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed four million megawatt hours.²³³

NOPR Proposal

334. In the NOPR, the Commission estimated that approximately 418 of the 1,730 registered transmission owners, generator owners and distribution service providers may fall within the definition of small entities. Further, the Commission estimated that of the 418 small entities affected there are 50 within the NPCC region that would have to comply with the rulemaking. The Commission contemplated that the rulemaking would

²³¹ 5 U.S.C. 601-612 (2006).

²³² 13 CFR 121.101.

²³³ 13 CFR 121.201, Sector 22, Utilities & n.1.

affect more small entities in the NPCC Region than those outside NPCC because there are more elements in the NPCC region that would be added to the bulk electric system based on the new definition than elsewhere. The Commission estimated the first year affect on small entities within the NPCC region to be \$39,414.²³⁴ This figure is based on information collection costs plus additional costs for compliance.²³⁵ The Commission estimated the average annual affect per small entity outside of NPCC will be less than for the entities within NPCC. In the NOPR, the Commission stated that it did not consider this to be a significant economic impact for either class of entities because it should not represent a significant percentage of the operating budget.

Comments

335. APPA asserts that the Commission underestimates the costs of compliance for small utilities. According to APPA, the Commission's assumption that utility staff would conduct an analysis is not merited in the case of many small entities. APPA states that many of its smaller members do not have the in-house employees and resources to conduct such reliability analyses and would have to rely on outside consultants and legal

²³⁴ For companies registered as more than one entity in the NERC compliance registry this figure will increase accordingly. That is, if a company is registered as a transmission owner and generator owner then the cost burden would be \$78,828 (\$39,414*2 = \$78,828).

²³⁵ We use fifty percent of the first year "number of hours per response" figure in the information collection statement for calculation under the assumption that smaller entities do not have complicated systems or will not have as many new elements on average as larger entities do.

firms. Therefore, APPA estimates that the fees small utilities would pay for each of the services as follows, based on information and belief: Consulting Engineer, \$225/hour; Record Keeping, \$75/hour; and Legal, \$500/hour. According to APPA, these increased dollar estimates alone substantially increase the burden estimates on smaller utilities to comply with the Commission's proposals. WPPC believes that the cost to satisfy transmission owner/transmission operator certification alone would be \$80,000. WPPC points to one small municipally-owned utility paid \$40,000 for third party expertise and review of the utility's required compliance. WPPC adds that the municipality had two staff members spend a week reviewing a modifying city policies to ensure compliance with reliability standards. WPPC points out that these costs only represent the initial subject matter review and do not include subsequent implementation, training or material purchase costs. WPPC also states that small entities have to divert employees from other tasks to compliance tasks which represents a significant burden on staffing.

336. ISO New England does not believe that the NOPR cost estimate captures the cost of physical upgrades that might be necessary on the system. The cost estimates do not reflect the true financial burden that might be borne by these smaller entities.

337. BPA is concerned that the Commission is underestimating the costs and resources associated with reliability compliance. BPA disagrees with the Commission's estimated annual costs of \$39,414 for entities that are required to newly comply with Reliability Standards as a result of adopting the definition. BPA believes that the Commission's figure vastly underestimates the actual effort and costs associated with compliance. In BPA's experience with its customers, the smallest customer impact is equivalent to at

least one FTE, and larger customers have indicated they have an even higher burden. BPA asserts that the Commission's estimates also overlook indirect compliance costs and their impact on small and large entities alike. BPA disagrees with the Commission's conclusion that the compliance burden is not "a significant economic impact . . . because it should not represent a significant percentage of the operating budget." It is BPA's experience that implementing a fully functioning compliance program requires committed personnel, budget, and resources, which is never insignificant.

Commission Determination

338. The Commission disagrees with commenters that challenge the Commission's conclusion that the rule will not have a significant economic impact on a substantial number of small entities. We are not persuaded by APPA, BPA and ISO New England's assertions regarding how the Commission's analysis is erroneous or in what ways the Final Rule will have a significant economic impact on a substantial number of small entities. As the Commission stated in its NOPR, most transmission owners, transmission operators and transmission service providers do not fall within the definition of small entities. In addition, the requirement to comply with the definition of bulk electric system is not new. The reason for revising the definition of bulk electric system is to comply with the Commission's directives and address the technical and policy concerns expressed in Order Nos. 743 and 743-A, which NERC accomplished by eliminating the explicit basis of authority for Regional Entity discretion in the current definition, and establishing specific threshold criteria rather than general guidelines of facilities operated or connected at or above 100 kV. Thus, while the Commission recognizes that some

small entities within the NPCC territory may have an increased burden due to multiple registration classifications or increased compliance with the Reliability Standards due to the elimination of the regional discretion, the average annual affect per small entity outside of NPCC will be less than for the entities within NPCC and should not materially change. The Commission also does not consider this to be a significant economic impact for either class of entities because our estimated costs for complying with the revised definition should not represent a significant percentage of the operating budget. Further, while NYPSC and Massachusetts DPU assert that the costs for compliance will be \$280 million they make no specific reference to the cost for small businesses and, as noted above, their estimate does not account for the revised language in the definition of bulk electric system and the specific inclusions and exclusions that we are approving in this Final Rule. Accordingly, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

V. Environmental Analysis

339. 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.²³⁶ The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human

²³⁶ *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986-1990 ¶ 30,783 (1987).

environment. The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.²³⁷ Accordingly, neither an environmental impact statement nor environmental assessment is required.

VI. Document Availability

340. 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.

341. 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.

342. 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)

²³⁷ 18 C.F.R. § 380.4(a)(5).

502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referencerom@ferc.gov.

VII. Effective Date and Congressional Notification

343. These regulations are effective [insert date 60 days from the later of the date Congress receives the agency notice or the date the rule is published 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.

List of subjects in 18 CFR Part 40

By the Commission. Commissioner Clark is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A

American Electric Power Service Corporation (AEP)
American Municipal Power, Inc. (AMP)
American Public Power Association (APPA)
American Wind Energy Association (AWEA)
Arizona Public Service Company (Arizona Public Service)
Barrick Goldstrike Mines Inc. (Barrick)
Associated Electric Cooperative, Inc., Basin Electric Power Cooperative, Tri-State Generation and Transmission Association, Inc. (the G&T Cooperatives)
Bonneville Power Administration (BPA)
City of Alameda, California (Alameda)
City of Anaheim, California (Anaheim)
City of Redding, California (Redding)
City of Riverside, California (Riverside)
Cogeneration Association of California and the Energy Producers and Users Coalition
Consumers Energy Company (Consumers)
Dominion Resources Services, Inc. (Dominion)
Dow Chemical Company (Dow)
Duke Energy Corporation (Duke Energy)
Edison Electric Institute (EEI)
Electricity Consumers Resource Council (ELCON)
Exelon Corporation (Exelon)
Florida Reliability Coordinating Council, Midwest Reliability Organization, Northeast Power Coordinating Council, Inc., ReliabilityFirst Corporation, Southwest Power Pool Regional Entity, SERC Reliability Corporation, Texas Reliability Entity, Inc., Western Electricity Coordinating Council (the Regional Entities)
City of Holland, Michigan Board of Public Works (Holland)
Hydro One Networks Inc. and the Independent Electricity System Operator (Hydro One)
Hydro Quebec Transenergie (Hydro Quebec)
Idaho Power Company (Idaho Power)
Imperial Irrigation District (IID)
Industrial Customers of Northwest Utilities (ICNU)
Industrial Users of Utah (IUU)
International Transmission Company d/b/a ITC Transmission, Michigan Electric Transmission Company, LLC, ITC Midwest LLC and ITC Great Plains LLC (ITC)

ISO New England Inc. (ISO New England)
Kansas City Power & Light Company and KCP&L Greater Missouri (KCP&L)
Large Public Power Council (LPPC)
Massachusetts Department of Public Utilities (Massachusetts DPU)
Midwest Independent Transmission System Operator, Inc. (MISO)
MISO Transmission Owners
National Association of Regulatory Utility Commissioners (NARUC)
National Grid USA (National Grid)
National Rural Electric Cooperative Association (NRECA)
Nevada Power Company and Sierra Pacific Power Company (NV Energy)
New England States Committee on Electricity (NESCOE)
New York Independent System Operator, Inc. (NYISO)
New York State Public Service Commission (NYPSC)
North American Electric Reliability Corporation (NERC)
North Carolina Eastern Municipal Power Agency (“NCEMPA”) and North Carolina Municipal Power Agency Number 1 (“NCMPA1”) (together “Power Agencies”)
Oglethorpe Power Corporation, Georgia Transmission Corporation and Georgia System Operations Corporation
Old Dominion Electric Cooperative (ODEC)
Occidental Energy Ventures Corp
Pennsylvania Public Utility Commission
Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company, Atlantic City Electric Company (PHI Companies)
Portland General Electric Company (Portland)
Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC (PSEG Companies)
SmartSenseCom, Inc. (SmartSenseCom)
Snohomish County PUD No. 1 (Snohomish)
Southern California Edison Company (SoCal Edison)
Southern Company Services, Inc. (Southern Companies)
Springfield Utility Board (Springfield)
Steel Manufacturers Association
Transmission Access Policy Study Group (TAPS)
Utility Services, Inc.
Valero Services, Inc (Valero)
Western Public Power Coalition (WPPC)
White River Electric Association, Inc. (WREA)

Revisions to Reliability Standard for Transmission Vegetation Management) **Docket No. RM12-4-000**

the Violation Risk Factor for Requirement R2, and approve the remainder of the Violation Risk Factors. In response to the Commission's request for comments, NERC addresses several sections of the NOPR, as further discussed below. NERC respectfully requests that the Commission carefully consider the issues raised and approve the proposed Reliability Standard as filed. For ease of reference, excerpts from the Commission's NOPR appear below.

I. Notices and Communications

Notices and communications with respect to this filing may be addressed to:⁴

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile

Charles A. Berardesco*
Senior Vice President, General Counsel and
Corporate Secretary
Holly A. Hawkins*
Assistant General Counsel
William H. Edwards*
Attorney
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
william.edwards@nerc.net

II. Proposal to Approve FAC-003-2

NERC supports the Commission's proposal to approve the proposed Reliability Standard. FAC-003-2 represents a significant step in transmission vegetation management. The proposed FAC-003-2 Reliability Standard maintains a reliable electric transmission system using a defense-in-depth strategy to manage vegetation located on transmission Rights-of-Way and by minimizing encroachments from vegetation located adjacent to the Rights-of-Way and within the

⁴ Persons to be included on the Commission's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

Transmission Owner’s control, thus preventing the risk of those vegetation-related outages that could lead to a Sustained Outage.⁵ Additionally, the proposed FAC-003-2 standard would enhance reliability by improving enforceability of the FAC-003 Reliability Standard, as compared to FAC-003-1. As the Commission states in its NOPR, proposed standard FAC-003-2 is an improvement over the currently-effective Version 1 standard and will support vegetation management practices that can effectively protect against vegetation-related transmission outages.⁶ NERC also recognizes the Commission’s statement in the NOPR that it gives due weight to NERC’s technical expertise in considering whether to approve proposed Reliability Standard FAC-003-2. NERC requests that the Commission continue to give “due weight” to NERC’s technical expertise and approve the proposed Reliability Standard as filed.⁷

III. Applicability

A. Information on IROL Status

In paragraph 64 of the NOPR, the Commission seeks a better understanding of how proposed FAC-003-2 will be applied to facilities designated as Interconnection Reliability Operating Limits (IROLs).⁸ Specifically, the Commission explains:

P 64. While we view the modified applicability as a significant improvement, there are two aspects on which we seek comment. First, section 4.2.2 of proposed FAC-003-2 provides that the standard applies to overhead transmission lines operated below 200

⁵ Section C.1.4 of the proposed FAC-003-2 standard lists seven types of outages that would be categorized as “Sustained Outages.”

⁶ NOPR at P 57.

⁷ Because a NOPR is not a final action, and the Commission continues to have the option to direct changes under section 215(d)(5) in its final rule, arguments that the Commission has failed to give due weight to NERC’s technical expertise are not yet moot. The Commission’s obligation under section 215(d)(2) of the Federal Power Act (“FPA”), 16 U.S.C. § 824o(d)(2) (2006), continues beyond an initial proposal to approve or remand a proposed or modified Reliability Standard and until the issuance of a final rule or order on the merits of NERC’s Petition.

⁸ An IROL is defined 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.” NERC defines “System Operating Limit” 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.” See NERC Glossary of Terms Used in Reliability Standards (“NERC Glossary”) at 26, 48.

kV identified as an IROL under NERC Standard FAC-014 by the planning coordinator. However, FAC-014-2 does not explicitly require the planning coordinator to provide information about IROL status to transmission owners. Further, IROLs may change with changing system conditions. Given these factors, we seek a better understanding of how FAC-003-2 will be applied to facilities designated as IROLs. For example, we seek comment on how information regarding IROL status will be transmitted to transmission owners that must comply with FAC-003-2 and how transmission owners can effectively implement vegetation management per FAC-003-2 given that such programs are generally implemented annually and a change in IROL status can take place at any time given changing system conditions.⁹⁴

⁹⁴ For example, if a line is designated to be an IROL element by the planning coordinator, how will the transmission owner know to thereafter apply FAC-003-2 to that line? If the designation of an IROL changes with changes in system conditions, how will a transmission owner document management of vegetation over time?

Section 4.2.2 of proposed FAC-003-2 relies on identification of IROLs by the Planning Coordinator to determine the applicability of proposed FAC-003-2 to certain transmission lines operated below 200 kV. The Planning Coordinator identifies IROLs per FAC-014⁹ using its methodology developed in FAC-010.¹⁰ Additionally, TPL-001, Requirement R6 requires the Planning Coordinator to define and document, within its Planning Assessment, the criteria or methodology used in the analysis to identify IROL system conditions (*i.e.* Cascading, voltage instability, or uncontrolled islanding), which are then used in its Planning Assessments.

The technical reference document for proposed FAC-003-2 explains the approach taken in proposed FAC-003-2 to rely on FAC-014 for identification of IROLs. Proposed FAC-003-2 relies on the identification of IROLs by the Planning Coordinator. FAC-014 requires Reliability Coordinators, Planning Coordinators, and Transmission Planners to have a methodology to identify all lines that might comprise an IROL. Thus, Planning Coordinators are able to identify sub-200 kV lines that qualify as part of an IROL and should be subject to proposed FAC-003-2.

⁹ See FAC-014, Requirement R3.

¹⁰ See FAC-010, Requirements R1-R5.

This would include identifying any changes in the status of a line if a line's IROL status changes given changing system conditions.¹¹

In an early version of the proposed Reliability Standard, the standard drafting team developed a draft Requirement for the preparation of a list of sub-200 kV transmission lines by the Planning Coordinator. This draft Requirement was deleted in part because some commenters noted that a similar identification of important circuits exists in FAC-014 and as such, this draft Requirement was unnecessary. Others noted ambiguities in the language of the draft Requirement itself. The technical reference document explains that FAC-014, Requirement R5 provides the mechanism for a Transmission Owner to obtain the information needed to comply with proposed FAC-003-2. In FAC-014, the Reliability Coordinator, Planning Authority¹² and Transmission Planner each are required to provide its SOLs and IROLs to entities with a reliability related need, such as a Transmission Owner, who request such information. Transmission Owners have a reliability-related need for IROL information, including changes in that information, due to proposed FAC-003-2. In practice, while a Transmission Owner is developing its annual work plan for vegetation management, the Transmission Owner who does not already have the IROL information would send a request to the Planning Authority for the list of circuits that are associated with the IROLs pursuant to Requirement R5 of FAC-014.

If the Commission does not agree that Transmission Owners can obtain information directly from Planning Coordinators under Requirement R5 of FAC-014, NERC submits that the Transmission Owners still have the means to obtain the information for purposes of complying

¹¹ For changes in the status of the applicability of a line, the proposed standard identifies five special cases. These cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date, including those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the proposed standard.

¹² The term "Planning Authority" included in FAC-014 was replaced in the NERC Functional Model with the term "Planning Coordinator." References to the Planning Authority and Planning Coordinator are synonymous.

with proposed FAC-003-2. First, certain Transmission Owners are also registered as “Transmission Operators” and would already receive the necessary IROL information pursuant to FAC-014. Pursuant to the explicit Sub-Requirements of Requirement R5 in FAC-014, the Transmission Operator would already know the IROLs it may develop (*see* Requirement R5.2) and receive IROL information from the Reliability Coordinator (*see* Requirement R5.1), the Planning Authority (*see* Requirement R5.3), and the Transmission Planner (*see* Requirement R5.4) directly upon request. Therefore, Transmission Owners also registered as Transmission Operators would have access to the Planning Coordinator’s IROL information pursuant to Requirement R5.3 of FAC-014. As of December 10, 2012, the NERC registry shows that nearly half of the total Transmission Owners are also registered as Transmission Operators. Transmission Owners who are not also registered as Transmission Operators must have transferred their Transmission Operator compliance responsibilities by written agreement.¹³ Generally these agreements permit or require sharing of reliability and operational information needed to comply with proposed FAC-003 via FAC-014 Requirement R5.3.

As an example, in NYISO’s form agreement for Transmission Owners posted on its public website, Transmission Owners are required under Section 2.02 to operate and maintain its facilities in accordance with all Reliability Rules.¹⁴ NYISO is required, under Section 2.10 to provide “the necessary information and support services to comply with their obligations.”¹⁵

As an additional communication method for identifying IROLs, Requirement R8 of TPL-001-2 requires each Planning Coordinator and Transmission Planner to distribute its Planning

¹³ In Appendix 5b to the NERC Rules of Procedure, section III(d)(1) and III(d)(2) of Appendix 5b states that “[a] Transmission Owner/Operator will not be registered based on these criteria if responsibilities for compliance with approved NERC Reliability Standards or associated Requirements including reporting have been transferred by written agreement to another entity that has registered for the appropriate function for the transferred responsibilities, Transmission Owner/Operator.”

¹⁴ See NYISO Transmission Owner Agreement, *available at* http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/nyiso_agreement/nyiso_to_agreement.pdf.

¹⁵ *Id.*

Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners and to *any functional entity that has a reliability related need and submits a written request for the information* within 30 days of such a request. A Transmission Owner responsible for compliance with the proposed FAC-003 Reliability Standard would qualify as a “functional entity” with a legitimate reliability need and be eligible to request its Planning Assessment.

The Commission also asks in footnote 94 how entities will document management of vegetation over time if the designation of an IROL changes. FAC-003-2 requires Transmission Owners to have evidence that they managed vegetation to prevent encroachment into the MVCD as described in Requirement R1. The proposed Reliability Standard properly declines to prejudge how an entity will document its management activities, but it is clear that it must be done. This will be evaluated through the compliance monitoring and enforcement program. While the burden is on the Transmission Owner to procure the information needed to identify lines subject to Requirement R1, NERC argues that this burden is proper since the Transmission Owner is the entity responsible for implementing proposed FAC-003-2 and maintaining the transmission line.

B. Order No. 693, P 65 Directive

The Commission also seeks comment on whether proposed FAC-003-2 ensures that the standard covers “lines that have an impact on reliability” in compliance with the Commission’s Order No. 693 directive to expand the applicability of the Reliability Standard. In its NOPR, the Commission states:

P 65. Second, in Order No. 693, the Commission directed that the proposed Reliability Standard apply to “Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO.” The Commission noted evidence that some lines below 200 kV can have significant impacts on the Bulk-Power System, including IROLs and System Operating Limits (SOLs).

The Commission directed the ERO, however, to balance extending the applicability of the standard against unreasonably increasing the burden on transmission owners. Thus, we seek comment on how the applicability of the proposed Reliability Standard complies with the directive that the standard cover “lines that have an impact on reliability.”

P 65 (cont’d). In addition, since the issuance of Order No. 693, we note that Commission staff and NERC stated in their joint report on the 2011 Southwest outage that failure to properly designate IROLs was a major cause of the outage. Therefore, as part of the broader inquiry into whether the standard covers “lines that have an impact on reliability,” we seek comment on how NERC will assure that IROLs are properly designated.

In Order No. 693, the Commission directed NERC to “modify the Reliability Standard to apply to Bulk-Power System transmission lines that have an impact on reliability *as determined by the ERO.*”¹⁶ The directive requires a determination by the ERO rather than an objective statement that the revised Reliability Standard cover “lines that have an impact on reliability.” NERC responds that it has properly modified the applicability of the Reliability Standard to cover transmission lines that have an impact on reliability while properly balancing the extension of the applicability of the standard against unreasonably increasing the burden on Transmission Owners.

As in the FAC-003-1 Reliability Standard, proposed FAC-003-2 continues to apply to transmission lines operated at 200 kV or higher. In addition, in response to the Commission directive, proposed FAC-003-2 also applies to critical transmission lines below 200 kV. Rather than employing a bright-line threshold of 100 kV, the applicability for transmission lines below 200 kV has been limited to specific cases where lines are critical to reliability by virtue of their inclusion as elements in the determination of an IROL or as a part of a Major WECC Transfer

¹⁶ *Id.* (emphasis added).

Path.¹⁷ The standard drafting team took this approach to avoid the creation of a generic lower bright-line. By relying on IROL and Major WECC Transfer Path identification as a proxy for reliability importance, the proposed standard uses an impact-based approach for determining applicability. This impact-based approach balances the importance of covering lines that have an impact on reliability without unreasonably increasing the burden on Transmission Owners.

In its NOPR, the Commission asks how NERC will assure that IROLs are properly designated in light of the 2011 Southwest outage. The Arizona-Southern California Outage report provides recommendations for addressing the failure to properly designate IROLs in that outage and efforts are underway to implement those recommendations. With respect to determining compliance with proposed FAC-003-2, NERC and the Regional Entities will continue to enforce the FAC-014-2 and FAC-010-2.1 Reliability Standards to ensure Planning Coordinators are identifying IROLs using their developed methodology.

IV. Requirements R1 and R2

A. Minimum Clearance Values

The Commission also seeks comment on the status of industry research regarding testing or analysis of flashover events. In addition, the Commission seeks comment on a proposal to direct NERC to conduct confirmatory empirical research to confirm the MVCD values in proposed FAC-003-2. The Commission's states in the NOPR:

P 72. Notwithstanding our approval of the proposed MVCD, we remain concerned, as indicated in Order No. 693, over the lack of empirical data with regard to actual flashover distances observed through testing or analysis of flashover events. NERC states in its petition that the Electric Power Research Institute (EPRI) is planning to undertake "the first known field tests of energized high voltage conductor flash-over to vegetation" at its Lenox facility,

¹⁷ WECC maintains a listing of Major WECC Transfer Paths available on its website, *available at* <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf>.

and that EPRI could be ready to commence such testing by the summer of 2013. We seek comment on the status of this project and any other similar testing that is planned or ongoing of which NERC or other commenters are aware.

P 73. While we accept NERC's approach to determine the MVCDs between conductors and vegetation needed to prevent flashovers, we believe it is important that NERC develop empirical evidence that either confirms the MVCD values or gives reason to revisit the Reliability Standard. Accordingly, consistent with the activity that NERC has already initiated, the Commission proposes to direct that NERC conduct or commission testing to obtain empirical data and submit a report to the Commission providing the results of the testing. We seek comment on this proposal, as well as the appropriate time frame for completion of the required testing and the submission of a report.

At this time, NERC does not have an update to provide to the Commission with additional information on the status of EPRI's or other similar testing that is planned or ongoing. As to the development of confirmatory empirical data as noted in the NOPR, given the uncertainty in timing, funding, design, scope, and execution of such a study described below, NERC offers the following alternative to a Commission directive. Because the Commission is proposing to approve the proposed FAC-003-2 Reliability Standard, including its proposed MVCD values, NERC asks that the Commission refrain from issuing a directive and instead accept NERC's commitment to work with the Commission and other entities or groups to determine whether and how a study could be conducted to obtain the empirical data the Commission seeks and to evaluate whether there is reason to revisit the Reliability Standard. This alternative would allow NERC the flexibility to pursue additional discussion with the Commission on scoping and funding and allow for the development of possible partnerships in conducting the study. This approach would also allow Commission staff, NERC, and the industry to collaborate on the study and also on any necessary changes to the proposed Reliability Standard. Such a collaborative effort would also reduce the future need for additional

studies. Accordingly, if the Commission concludes confirmatory empirical data is necessary, NERC requests the Commission to accept NERC's proposed approach in lieu of a directive.

If the Commission issues a directive to NERC to conduct the empirical research, NERC requests the Commission to provide additional guidance with respect to the following three concerns: (1) the need for the empirical data and the scope of a study; (2) time frame for the study; and (3) funding of the study. NERC also requests that the Commission tailor any directive to allow NERC flexibility regarding timing, study design, study scope, and funding.

First, the Commission states in the NOPR that it believes it is important that NERC develop this empirical evidence, but does not provide details on why confirmatory research is necessary in light of its support for the proposed Reliability Standard and its statements that NERC has supported its use of the MVCD values. NERC requests that the Commission explain the need for the confirmatory research to aid NERC, or a commissioned entity, in the study design. This information would be critical in developing a study to verify the MVCD values and specifically in determining what data is needed to address the areas in which the Commission sees a lack of supporting empirical data for the MVCD values in proposed FAC-003-2.

NERC seeks guidance from the Commission on what type of information is envisioned when it refers to "empirical data." This would help ensure that the study produces the types of necessary data the Commission needs. The type of empirical data the Commission needs would also largely affect the cost of any study. For example, if the study required testing of actual observed flashover in a controlled environment, the cost could be significant and the study could require multiple years to complete. If the study would collect and analyze contacts annually or over a span of years, the cost would be less and still provide useful data.¹⁸

¹⁸ For example, NERC already creates a quarterly Vegetation-Related Transmission Outage Report that provides a summary of the vegetation outages that occurred by voltage class and category. *See, e.g.* NERC

Second, NERC cannot provide an estimate, with any accuracy, on the time it may take to comply with a Commission directive. If directed to conduct the study, NERC requests that it be allowed to submit a proposed time schedule for completion once NERC has an opportunity to determine the time needed to properly design the study, budget for the study, conduct the testing, process the results, compile a report, and file with the Commission.

Third, supplemental funding would be required to complete the study. The Commission should make clear that funding would be provided. The Commission's regulations require the ERO to file its proposed entire annual budget for statutory and non-statutory activities with the Commission 130 days before the beginning of the ERO's fiscal year. The budget for fiscal year 2013 has already been submitted and approved by the Commission.¹⁹ NERC does not currently have the necessary budget to undertake confirmatory research that could be required to confirm the MVCD values. Therefore, NERC asks the Commission to address funding of such a directive and allow for time to seek necessary Commission approval for supplemental funding. Prior to any budget request, NERC would need to have an accurate estimate of the cost of the proposed study, which would take time and resources to design.

B. Designation of a Medium Violation Risk Factor for Requirement R2

The Commission states in the NOPR that NERC has not supported a "medium" Violation Risk Factor designation for Requirement R2 and provides an opportunity for NERC to provide additional explanation. The NOPR explains:

P 77. Based on the information provided in NERC's Petition, it is not clear that NERC has adequately supported a medium Violation Risk Factor designation for Requirement R2. ... NERC's support for the medium designation is that transmission lines that are not IROLs and are not Major WECC Transfer Paths "have less

Vegetation-Related Transmission Outage Fourth Quarter 2011 Report, *available at* http://www.nerc.com/files/4Q2011_Vegetation%20Report%20Updated%20FINAL.pdf.

¹⁹ *North American Electric Reliability Corp.*, 141 FERC ¶ 61,086 (2012).

potential for leading to cascading, separation, or instability” than lines that are IROLs or Major WECC Transfer Paths. But NERC does not explain *why* outages on these relatively high voltage lines (200 kV or higher) would not likely lead to cascading, separation, or instability, or provide any indication of the number of transmission lines and transmission line-miles that would now be subject to a reduced (i.e., medium) Violation Risk Factor designation if FAC-003-2 were in effect.

P 81. Accordingly, pursuant to our Violation Risk Factor guidelines, which require, among other things, consistency within a Reliability Standard (guideline 2) and consistency between requirements that have similar reliability objectives (guideline 3), we propose to modify the Violation Risk Factor assigned to Requirement R2 from medium to high. However, in its comments on this NOPR, NERC is free to provide additional explanation than provided thus far to demonstrate the lines identified in Requirement R2 are properly assigned a medium Violation Risk Factor.

NERC does not have additional information beyond the information supplied in its petition for the Violation Risk Factor set for Requirement R2. NERC submits that the “medium” designation is appropriate and aligns with the Commission-approved definitions for Violation Risk Factors and complies with the Commission’s guidelines regarding the establishment of these values. 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 Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not an element of an IROL or a Major WECC Transfer Path. Applicable lines that are not an element of an IROL or Major WECC Transfer Path do require effective vegetation management, but these lines are comparatively less operationally significant.

C. Enforceability

a. Consolidation of Reference Material

In its NOPR, the Commission asks whether the information that NERC has provided in its Petition, in the Guideline and Technical Basis document that is attached as part of Exhibit A to the Petition, and in its May 25, 2012 responses to the Commission staff's data requests should be consolidated as reference material. The NOPR reads:

P 91. We seek comment as to whether this material should be consolidated as reference material to complement the proposed compliance measures in order that entities that must comply can find these materials in one place and assure implementation of the proposed standard as NERC has supported in its filings.

NERC does not object to consolidating the information as reference material and posting it on its website along with proposed FAC-003-2 prior to implementation.

b. Communication Delay

In its NOPR, the Commission seeks comment on how NERC would treat certain delays in communication. The Commission states:

P 92. In addition, Requirement R4 requires transmission owners to notify "without [any][sic] intentional time delay" the control center with switching authority for the applicable line when the transmission owner has confirmed the existence of a vegetation condition that is likely to cause an imminent fault. We seek comment on how NERC would or should treat a delay in communication caused by the negligence of the transmission owner or one of its employees, where the delay may be significant and "unintentional."

NERC responds that the ultimate treatment of a delay by a Compliance Enforcement Authority would take into account the specific facts and circumstances underlying the issue and must be determined on a case-by-case basis. However, the expectation in Requirement R4 is that once a Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause an imminent fault, the Transmission Owner must immediately notify the control center.

The standard drafting team did not include a quantitative time element for notification in Requirement R4 due to the difficulty in determining one time period that applies to all cases. The proposed FAC-003-2 technical reference document offers examples of acceptable unintentional delays, such as certain limited communication system problems, delays due to the location of crews in remote areas with no communication access, or delays due to severe weather. However, NERC again notes that any determination would need to be made on a case-by-case basis.

A. Reporting Requirements

In the NOPR, the Commission asks NERC to identify the courses of action available to it to ensure compliance. The NOPR states:

P 94. However, we seek comment on NERC’s statement regarding the “courses of action” that are available to it in order to ensure compliance, other than notifying the Commission of the entity’s failure to comply.

NERC’s statement was a reiteration of Section 100 of the NERC Rules of Procedure. For ease of reference, excerpts from Section 100 referenced in the Petition are provided below:

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.²⁰

²⁰ See NERC Dec. 21, 2011 Petition at 31 (quoting Section 100 of the NERC Rule of Procedure).

As an example of a course of action, Attachment 1 of NERC’s Compliance Monitoring and Enforcement Program found in Appendix 4C of the NERC Rules of Procedure provides a process for non-submittal of requested data. Under this process, if data, information, or other reports requested from a Registered Entity are not received by a date certain, the Compliance Enforcement Authority may apply a Reliability Standard violation at the severe Violation Severity Level.

B. Definitions – Revised Definition of Right-of-Way

a. Transmission Owner Incentive to Narrow Right-of-Way

The Commission also expresses concern in the NOPR regarding a possible incentive for Transmission Owners to narrowly define a Right-of-Way. The Commission explains:

97. However, under proposed Requirements R1.2, R1.3 and R1.4 and the corresponding sub-requirements of R2, fall-ins, blow-ins and grow-ins that cause a sustained outage are violations of the proposed standard only if they occur from *inside* this newly-defined Right-of-Way, which could give transmission owners the perverse incentive to “define” a particular Right-of-Way as narrowly as possible in order to limit the likelihood of an R1 or R2 violation.

As an initial matter, NERC notes that the Commission’s statement in P 97 is partially incorrect with respect to grow-ins. In P 97, the Commission states that “under proposed Requirements R1.2, R1.3 and R1.4 and the corresponding sub-requirements of R2, fall-ins, blow-ins and grow-ins that cause a sustained outage are violations of the proposed standard *only if they occur from inside* this newly-defined Right-of-Way, which could give transmission owners the perverse incentive to ‘define’ a particular Right-of-Way as narrowly as possible in order to limit the likelihood of an R1 or R2 violation.”²¹ Under Requirements R1 and R2, an encroachment due to vegetation *growth* into the MVCD that caused a vegetation-related Sustained Outage,

²¹ NOPR at 97 (emphasis added).

regardless of the defined Right-of-Way, would be a violation of R1 and R2.²² Encroachments due to grow-ins into the MVCD are not tied to the Right-of-Way. However, violations of R1 and R2 due to fall-ins and blow-ins are violations of the proposed standard only if they occur from inside the defined Right-of-Way.

In response to P 97, while NERC understands the Commission's concern, no evidence is currently available or cited to show that this behavior is occurring or would occur. Transmission Owners are accountable for R1 and R2 purposes if the encroachment occurs from outside of the defined "Right-of-Way," but within the Transmission Owner's control. Encroachments into the MVCD observed in real time would be violations of R1 or R2 regardless of whether they cause a Sustained Outage and regardless of whether the vegetation is within the Right-of-Way as defined under proposed FAC-003-2. Encroachments due to vegetation growth into the MVCD also trigger violations of R1 and R2 regardless of the defined Right-of-Way.

For the remaining encroachments due to "fall-ins" or "blow-ins," the Transmission Owner still must have robust vegetation management practices in place and implement them effectively to properly manage danger timber outside of the Right-of-Way, but within the Transmission Owner's control, to ensure no encroachments occur. Otherwise, the Transmission Owner risks violating Requirements R6 and R7 of FAC-003-2, as described in response to P 101 of the NOPR below.

Given the significant cost and public scrutiny of a Sustained Outage, the incentive is there for Transmission Owners to properly set Right-of-Way widths to ensure that the land needed to operate a transmission line is included. This is especially true because the Transmission Owner has an obligation to implement the rigorous defense-in-depth strategy for vegetation management required by proposed FAC-003-2. As discussed in response to P 102 of

²² See Requirements R1 (#4) and R2 (#4) of FAC-003-2.

the NOPR below, in all cases, the width of the Right-of-Way must meet engineering or construction standards pursuant to the definition of Right-of-Way and cannot be arbitrarily set by the Transmission Owner.

b. Fall-in by Danger Timber

In its NOPR, the Commission seeks clarification of one of NERC's statements in its response to the Commission's data request in the proceeding. The Commission states:

P 101. However, we seek further comment on NERC's enforcement approach with respect to a fall-in by "danger timber" (dead, diseased or dying trees or limbs) from within the transmission owner's legally-owned and controlled right-of-way. Specifically, NERC indicates in its data responses (restated in P 98, *supra*) that "if the TO is regularly identifying its danger trees and has a program for managing the risk of fall-in there would be no violation." The Commission's concern is that this statement could be read to mean that, as long as the transmission owner identifies danger trees and has a program to manage the risk of those trees, an encroachment into the MVCD from a location within the transmission owner's control would not be a violation. The Commission would not agree with such a reading. The mere existence of a program to identify danger trees and a program to manage risk should not shield a transmission owner from enforcement if, notwithstanding the existence of the program, an encroachment into the MVCD occurred. The Commission seeks comment on this reading and, based on the comments, will consider whether changes are needed.

In its data request response, NERC explained a series of scenarios where the vegetation is located outside of the Transmission Owner-defined Right-of-Way, but within the Transmission Owner's control.²³ Two of the scenarios discussed fall-in of "danger" timber (dead, diseased or dying) and fall-in from a green, healthy tree from outside of the Right-of-Way, but within the Transmission Owner's control. In its data response, NERC states "if the TO is regularly identifying its danger trees and has a program for managing the risk of fall-in there would be no

²³ NERC May 25, 2012 Data Responses, Response to Q9.

violation.”²⁴ The Commission states that it would not agree with such a reading. NERC offers the following additional explanation to clarify its statement in the data response.

Because there is no practical inspection program or technology capable of identifying which green or “healthy” trees may fall into the MVCD, the Requirements in proposed FAC-003-2 do not require the cutting of green, “healthy” trees. However, because danger timber is identifiable, it is important to incentivize Transmission Owners to have effective vegetation management practices to manage the risk of the danger timber outside of the Right-of-Way, but within the Transmission Owner’s control.²⁵ NERC explained in its data response that if an outage occurs and it is confirmed that the Transmission Owner was not attempting to identify its danger timber risk, the Transmission Owner could be in violation of Requirement R6, which requires a Transmission Owner to perform a Vegetation Inspection of 100% of its applicable transmission lines subject to proposed FAC-003-2. Also, if the Transmission Owner identifies the danger tree, but puts no plan into effect to manage the risk of fall-in, the Transmission Owner could be in violation of R7, which requires a Transmission Owner to complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. The same is the case if the Transmission Owner had knowledge of a probable encroachment into the MVCD and did nothing to eliminate the encroachment.

NERC’s statement “if the TO is regularly identifying its danger trees and has a program for managing the risk of fall-in there would be no violation” is accurate so long as the Transmission Owner implements a well-managed and executed vegetation management program as documented under Requirement R3 and as carried out through the risk-based Requirements

²⁴ *Id.*

²⁵ The Transmission Owner’s initial commitment to manage danger timber is measured under Requirement R3, which states that the “Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD...”

R6 and R7. The reference to “no violation” in NERC’s explanation pertained to Requirements R6 and R7, but was not intended to convey that mere existence of a program to identify danger trees and a program to manage risk would create a shield from a finding of a violation under Requirements R1 or R2 if an encroachment does occur. Requirements R6 and R7 collectively demonstrate how entities carry out their Requirement R3 documented vegetation management program, and Requirements R1 and R2 ultimately ensure their overall performance success.

c. Defining a Right-of-Way

The Commission also requests comment in the NOPR on how Transmission Owners will use the guidance identified in the definition of Right-of-Way. The Commission states:

102. We also note that the proposed definition of Right-of-Way includes guidance as to how the transmission owner may define its Right-of-Way, requiring that it be based on construction documents, pre-2007 vegetation maintenance records, or as-built blowout standards. We seek comment on how the identified guidance in the new definition will be used: (1) by the transmission owner to establish criteria to determine an appropriate Right-of-Way; and (2) by auditors to establish criteria to determine compliance with the proposed standard.

Prior to answering the two specific questions in P 102, NERC would like clarify that the definition of Right-of-Way requires that the width of the corridor to be established *by engineering or construction standards* as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The three types of information identified in the definition are the criteria with which the Transmission Owner would be judged on whether it set the width of the Right-of-Way using sound engineering or construction standards. The Right-of-Way definition is intended to recognize more clearly the establishment of the Right-of-Way through documentation. In all cases, the width of the Right-of-Way must meet engineering or construction standards and

cannot be arbitrarily set by the Transmission Owner. Three types of information have been included in the definition as guidance to base and subsequently to verify that the width of the Right-of-Way has been properly determined.

To determine the width needed to operate a transmission line and define its Right-of-Way to meet engineering or construction standards, Transmission Owners currently calculate the blowout of the line and then add a spark over distance. The Transmission Owner would also consider the land use adjacent to the Right-of-Way and determine whether any additional width is necessary. The revised definition of Right-of-Way would require the width of the Right-of-Way to be based on construction documents, pre-2007 vegetation maintenance records, or as-built blowout standards. Construction documents would show the initial cleared width for the transmission line marked on drawings. Pre-2007 vegetation maintenance records are included in the revised definition so that in absence of a width provided in construction or engineering documents, the width can be set using evidence in maintenance records for a width that was *in fact* maintained prior to the FAC-003 Reliability Standard becoming mandatory. This information could be found in either inspection documents or bid documents for the transmission line.

The “blowout standard” is intended to represent the conductor “blow out” (as opposed to vegetation “blow in”) design criteria used when the line was constructed. This phrase in the definition allows a Transmission Owner to use engineering standards in effect when the line was constructed to determine the Right-of-Way width. From these types of information, the Transmission Owner will be able to determine the width needed to operate a transmission line. The Transmission Owner would not need to create a separate set of criteria to analyze the information from these types of guidance and set the width properly.

Auditors or other compliance monitoring staff will be able to request any supporting information used to set the width of the Right-of-Way and the Transmission Owner's support for its determination, which would need to include any of the available information listed in the definition of Right-of-Way. Auditors will be able to check that the width of the Right-of-Way is set according to engineering or construction standards and based on construction documents, pre-2007 vegetation maintenance records, or as-built blowout standards as required by the definition of Right-of-Way. In determining compliance with proposed FAC-003-2, the auditor would audit based on the width determined by the Transmission Owner.

V. CONCLUSION

For the reasons stated above, NERC respectfully requests that the Commission give "due weight" to NERC's technical expertise with respect to the content of proposed Reliability Standard FAC-003-2 and approve the proposed standard as filed.

Respectfully submitted,

/s/ William H. Edwards

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President, General Counsel and
Corporate Secretary
Holly A. Hawkins
Assistant General Counsel
William H. Edwards
Attorney
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
william.edwards@nerc.net

Dated: December 21, 2012

*Counsel for 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 this proceeding.

Dated at Washington, D.C. this 21st day of December, 2012.

/s/ William H. Edwards

William H. Edwards
*Attorney for North American
Electric Reliability Corporation*

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

NORTH AMERICAN	)	Docket Nos. RM05-17-000
ELECTRIC RELIABILITY CORPORATION	)	RM05-25-000
	)	RM06-16-000

**NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION RELIABILITY
STANDARDS DEVELOPMENT PLAN 2013-2015 INFORMATIONAL FILING
PURSUANT TO SECTION 310 OF THE NERC RULES OF PROCEDURE**

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability
Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President, General Counsel and
Corporate Secretary
Holly A. Hawkins
Assistant General Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net

December 31, 2012

TABLE OF CONTENTS

I. INTRODUCTION	1
II. NOTICES AND COMMUNICATIONS	2
III. BACKGROUND	2
A. Summary of 2013-2015 Development Plan	4
B. Project Schedule and Timeline Updates	4
IV. CONCLUSION	13

ATTACHMENTS

EXHIBIT A: *Reliability Standards Development Plan: 2013–2015*

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN	)	Docket Nos.	RM05-17-000
ELECTRIC RELIABILITY CORPORATION	)		RM05-25-000
	)		RM06-16-000

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION RELIABILITY
STANDARDS DEVELOPMENT PLAN 2013-2015 INFORMATIONAL FILING
PURSUANT TO SECTION 310 OF THE NERC RULES OF PROCEDURE

I. INTRODUCTION

The North American Electric Reliability Corporation (“NERC”) hereby submits to the Federal Energy Regulatory Commission (“FERC”) for informational purposes its Reliability Standards Development Plan in accordance with Section 310 of the NERC Rules of Procedure. The *Reliability Standards Development Plan: 2013-2015* (“2013 Development Plan”), is included as **Exhibit A**. The NERC Board of Trustees approved the 2013 Development Plan on December 19, 2012.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:¹

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability
Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco*
Senior Vice President and General Counsel
Holly A. Hawkins*
Assistant General Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net

III. BACKGROUND

In 2006, NERC developed an initial version of the plan for Reliability Standards development entitled the *Reliability Standards Development Plan: 2007–2009*. NERC has since updated the plan annually, and the 2013–2015 version of the plan is presented in this filing. The 2013 Development Plan is intended to:

1. Serve as a management tool to guide and coordinate the development of Reliability Standards and provide benchmarks for assessing progress;
2. Serve as a communications tool for coordinating standards development work with applicable governmental agencies in the United States and Canada and for engaging stakeholders in Reliability Standards development activities; and
3. Provide a basis for developing annual plans and budgets for the NERC Reliability Standards program.

Consistent with previous versions, the 2013 Development Plan is filed for informational purposes. Therefore, no specific FERC action is requested at this time. The 2013 Development Plan builds upon the foundation established by previous plans and identifies the current plans and priorities for development and modification of NERC Reliability Standards in the immediate three-year time horizon.

¹ Persons to be included on the FERC's service list are indicated with an asterisk.

The 2013 Development Plan differs from prior development plans by outlining three major areas of work:

1. Resolution of FERC directives;
2. Completion of five-year reviews for Reliability Standards not previously reviewed; and
3. Completion of existing projects, facilitated by a review of all Reliability Standards against the Paragraph 81² and Results-Based Reliability Standards criteria,³ which will provide a framework for NERC to address emerging issues on a more timely basis.

Prior to the determination of this approach and as with the Reliability Standards Development Plan 2011-2013 and 2012-2014 Informational Filings,⁴ NERC requested industry input on potential future Reliability Standards development projects, and based on this input, included all projects in the work plan, with the exception of projects that were identified as candidates for dismissal⁵ or that require further evaluation by NERC's Reliability Issues Steering Committee (RISC)⁶ to determine if a Reliability Standard is the appropriate solution.

NERC anticipates the Reliability Standards development work outlined in the 2013 Development Plan will be dynamic, and will be updated periodically as projects are completed or as new needs are identified and projects considered. NERC also recognizes that new priorities

² The Paragraph 81 project was initiated in response to Paragraph 81 of FERC's March 15, 2012 Order issued on NERC's Find, Fix and Track process. 138 FERC ¶61,193. The purpose of the project is to retire or modify FERC-approved Reliability Standard requirements that as FERC noted, "provide little protection to the reliable operations of the BES", are redundant or unnecessary, or to retire or modify a FERC-approved Reliability Standard requirement to increase the efficiency of the ERO's compliance programs. Phase 1 of the project identifies Reliability Standard requirements that clearly meet the criteria set forth in the SAR and do not require extensive technical research. Subsequent phases will address Reliability Standard requirements that need additional technical research before retirement or modification.

³ Guidance for developing Results-based Reliability Standards is available at the following link: http://www.nerc.com/docs/standards/sar/Resulted_Based_Standard_Guidance.pdf.

⁴ See, , North American Electric Reliability Corporation Reliability Standards Development Plan 2012-2014 Informational Filing, December 13, 2011, Docket Nos. RM05-17-000, RM05-25-000, RM06-16-000 ("2012 Development Plan"); North American Electric Reliability Corporation Reliability Standards Development Plan 2011-2013 Informational Filing, April 5, 2011, Docket Nos. RM05-17-000, RM05-25-000, RM06-16-000 ("2011 Development Plan").

⁵ These projects are identified in the 2013 Development Plan.

⁶ The RISC was established by the NERC Board of Trustees in August 2012. The RISC is an advisory committee that reports directly to the NERC Board of Trustees, providing early stage high-level leadership and accountability for nominated issues of strategic importance to bulk power system reliability. More information on the RISC is available at: <http://www.nerc.com/page.php?cid=11117428>.

may require flexibility in work planning to ensure the activities are given appropriate resources and priority.

By this filing, NERC informs FERC and other interested parties of the significant changes to the content of the 2012 Development Plan that led to the creation of the 2013 Development Plan. NERC identifies below changes in project timelines and completion dates originally outlined in the 2012 Development Plan that are reflected in the 2013 Development Plan.

A. Summary of 2012 Development Plan

The 2013 Development Plan differs from prior development plans as it broadens the scope to include three areas of work to be completed and covers all currently identified Reliability Standards development projects in the plan. Prior development plans established a fixed number of projects to be completed during the time period and prioritized the order in which projects would be in active development. The new approach eliminates the necessity for a prioritization as all projects will be in active development. To facilitate sufficient resources to accomplish this, NERC reorganized its standards department staff to focus the majority of staff on production, with more staff focused on leading standard drafting teams in the development of Reliability Standards.

B. Project Schedule and Timeline Updates

The 2012 Development Plan identified fourteen (14) active projects to be conducted over the three year period, of which eight (8) have been completed and six (6) have a planned completion date in 2013.

Projects that were listed in the 2012 Development Plan as active are:

Completed (8)

- 2006-06 Reliability Coordination
- 2007-03 Real-time Transmission Operations

- 2007-07 Vegetation Management
- 2007-17 Protection System Maintenance and Testing
- 2008-06 Cyber Security – Order 706
- 2009-01 Disturbance and Sabotage Reporting
- 2010-07 Generator Requirements at the Transmission Interface
- 2010-17 Definition of Bulk Electric System

To be completed (6)

- 2007-02 Operating Personnel Communication Protocols (schedule completion: second Quarter or Q2 of 2013)
- 2007-06 Protection System Coordination (schedule completion: Q2 of 2013)
- 2007-09 Generator Verification (schedule completion: Q2 of 2013)
- 2007-12 Frequency Response (May 31, 2013 filing deadline)
- 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves (May 31, 2013 filing deadline for BAL-012; target completion for remaining standards Q2 of 2013)
- 2010-05.1 Phase 1 of Protection Systems: Misoperations (schedule completion: Q1 of 2014)

In addition to projects listed in the 2012 Development Plan as active, the following five (5) projects that were not included in the 2012 Development Plan are currently in active development:

- 2006-02 Assess Transmission Future Needs and Develop Transmission Plans (Filed Oct 2011)
- 2010-13.2 Phase 2 of Relay Loadability: Generation
- 2013-02 Paragraph 81
- Definition of Adequate Level of Reliability
- 2010-11 TPL Table 1, Footnote B (schedule completion: Q2 of 2013)

NERC and the Regional Entities also completed development of an additional 12 projects that were not identified in the 2012 Development Plan:

- Project 2008-10 Interpretation of CIP-006-1 for Progress Energy

- Project 2009-19 BAL-002-0 R4 and R5 (NWPP Reserve Sharing Group)
- Project 2009-22 Interpretation of COM-002-2 for the IRC
- Project 2009-26 — Interpretation of CIP-004-1 for WECC
- Project 2010-INT-01 Rapid Revision of TOP-006-2 for Florida Municipal Power Pool
- Project 2011-INT-01 Interpretation of MOD-028 for Florida Power & Light Company (Rapid Revision Standard)
- Reliability Standard BAL-002-WECC-2 - Contingency Reserve
- Reliability Standard PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding
- Reliability Standard PRC-006-SERC-01 – Automatic Underfrequency Load Shedding Requirements
- Reliability Standard PRC-006-SPP-01 – Automatic Underfrequency Load Shedding
- Reliability Standard VAR-001-3 – Voltage and Reactive Control (WECC Regional Variance)
- Data Request for Order 754

IV. CONCLUSION

NERC respectfully requests that FERC accept this informational filing in compliance with Section 310 of the NERC Rules of Procedure.

Respectfully submitted,

/s/ Holly A. Hawkins

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability
Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 31st day of December, 2012.

/s/ Holly A. Hawkins

Holly A. Hawkins

*Assistant General Counsel for the North
American Electric Reliability Corporation*

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Standards Development Plan

2013-2015

Approved by Board of Trustees
TBD

RELIABILITY | ACCOUNTABILITY



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

Table of Contents

Chapter 1 – Executive Summary	1
Chapter 2 –Joint Letter from the Chair of the Standards Committee and NERC’s Vice-President and Director of Standards	3
Chapter 3 – Overview	4
New Approach to the Development Plan	4
NERC Standards’ Staff Reorganization	5
Streamlined Process	6
The Identification of Three Work Areas	8
Application of Paragraph 81 and Results Based Standards Concepts	9
Addressing Compliance Assessment Concerns	9
Chapter 4 – Production Status	11
Projects that were listed in the 2012-2014 RSDP as active:	11
Completed (8)	11
To be completed (6)	11
Progress on Regulatory Directives	12
Summary of Directives	13
Chapter 5 – Directives Team	15
Action Plan for Directives Team	16
Chapter 6 – Five-Year Reviews	19
Action Plan for Five-Year Reviews Team	20
Chapter 7 – Projects and Emerging Issues	24
Action Plan for Projects Team	24
Chapter 8 – Conclusion	27

Appendix 1 – Research.....	28
Appendix 2 – Assignment of Projects or Standards.....	29
Appendix 3 – Project Summaries.....	33
Project 2007-02 Operating Personnel Communication Protocols	33
Project 2007-06 System Protection Coordination.....	33
Project 2007-09 Generator Verification	34
Project 2007-11 Disturbance Monitoring.....	34
Project 2007-12 Frequency Response	34
Project 2007-17 Protection System Maintenance and Testing.....	35
Project 2008-01 Voltage and Reactive Planning and Control.....	35
Project 2008-02 Undervoltage Load Shedding.....	35
Project 2008-12 Coordinate Interchange Standards	36
Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	36
Project 2009-03 Emergency Operations.....	37
Project 2009-04 Phasor Measurements	37
Project 2009-05 Resource Adequacy Assessments	38
Project 2009-07 Reliability of Protection Systems	38
Project 2010-01 Support Personnel Training	39
Project 2010-02 Connecting New Facilities to the Grid.....	40
Project 2010-03 Modeling Data.....	40
Project 2010-04 Demand Data	41
Project 2010-05.1 Phase 1 of Protection Systems: Misoperations	41
Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS.....	42
Project 2010-08 Functional Glossary Model Revisions	42
Project 2010-13.2 Phase 2 of Relay Loadability: Generation	43

Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	43
Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	43
Project 2010-14.2 Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error, AGC, and Inadvertent.....	44
Project 2010-16 Definition of System Operator	44
Project 2010-17 Definition of Bulk Electric System	44
Project 2012-01 Equipment Monitoring and Diagnostic Devices.....	45
Project 2012-02 Physical Protection	45
Project 2012-03 PRC-004 VSLs.....	45
Project 2012-04 Protection System Commissioning Testing.....	46
Project 2012-05 ATC Revisions - Order 729.....	46
Project 2012-06 Generator Capabilities	47
Project 2012-07 Obsolescence Review.....	47
Project 2012-08 Glossary Updates	47
Project 2012-09 IRO Review	48
Project 2012-11 FAC Review.....	48
Project 2012-12 PER Review	48
Project 2012-13 NUC Review.....	48
Project 2012-14 Risk Analysis	49
Project 2012-15 Flow Limited Paths	49
Project 2013-01 Cold Weather Preparedness	49
Project 2013-03 Geomagnetic Disturbance Mitigation.....	50

Chapter 1 – Executive Summary

The 2013-2015 Reliability Standards Development Plan (RSDP) represents a bold new work plan for standards development, designed to transition from the existing set of NERC Reliability Standards to a clear, concise, and stable body of world-class, high-quality reliability standards that ensure the reliability of the bulk power system. At the same time, this plan brings the ERO standards program current with its obligations to address regulatory directives and conduct five-year reviews of all standards, all within the plan's 2013-2015 time horizon. NERC staff, the Standards Process Improvement Group (SPIG) and the Standards Committee (SC) have worked closely to conduct an intense evaluation of the current issues facing standards development. Based on this evaluation, this plan sets forth an approach that will result in a world-class body of reliability standards by 2015.

Specifically, in 2013, this new approach involves addressing three major areas of work:

- **Existing Projects/Emerging Issues** - Current projects must be completed and new projects that either support high risk reliability issues or emerging issues must be conducted in a timely and efficient manner
- **Reviews** - Five-year reviews must be conducted on standards that are due for assessment and have not been revised in recent standards development projects
- **Directives** - FERC directives must be addressed and the resulting revised standards filed

In addition, there are two major initiatives that will be applied across these three major work areas during their completion:

- Paragraph 81 concepts¹
- Results Based Standards²

These two initiatives will be applied to each standard or group of standards within the three major work areas ensuring requirements that do little to ensure the reliability of the bulk power system are eliminated and all new or revised standards are drafted as results-based standards. The use of these initiatives will lead to a concise set of standards that have the necessary combination of risk-, performance-, and capability-based requirements to ensure the reliability of the bulk power system in North America.

Further, another element to be applied, as appropriate, to the three major areas of work is the use of self-correcting language³ and/or the concurrent development of compliance information tools as may be proposed through the implementation of the Reliability Assurance Initiative (RAI). Further, close coordination between the standard drafting teams and NERC's Compliance Operations will be part of the overall drafting process.

¹ Information regarding Paragraph 81 can be located on the [project page for Paragraph 81 Phase I](#) on the NERC website.

² Information regarding Results Based Standards can be located on the NERC website under [Resource Documents for Standards](#).

³ For an example of self correcting language refer to how it was used for certain requirements in CIP version 5 standards.

In addition to developing a world-class body of standards, the standards development process is being revised in response to concerns raised by the NERC Board of Trustees (Board). Currently, the SPIG has recommended, and the SC and its subcommittees have developed, a set of changes which are intended to improve efficiency and the quality of standards. In response to a resolution issued by the Board at the November 2012 meeting calling for additional improvements in four areas, additional changes are being considered.

This document is meant to outline the activities in the development of reliability standards during 2013-2015. The work plan has been separated into the three work areas identified above. The areas are not exclusive; thus, although the work has been divided across the work teams, the individual standard drafting teams will continue to coordinate specific standards projects according to the scope of work assigned to the team by the Standards Authorization Request (SAR).

Chapter 2 – Joint Letter from the Chair of the Standards Committee and NERC's Vice-President and Director of Standards

To: NERC's Board of Trustees, Stakeholders, and Regulatory Authorities

The 2013-2015 Reliability Standards Development Plan is a vital ingredient towards transitioning from the existing set of standards to a clear, concise, and stable body of world-class, high-quality reliability standards that ensure the reliability of the bulk power system. At the same time, this plan brings the standards program current with its obligations to address regulatory directives and conduct five-year reviews of all standards.

To meet the objectives of the 2013-2015 RSDP will require a disciplined project management and review of current processes: streamlining the standards development process, suitably equipped standards drafting teams, and project management plans. Further, as new work is undertaken, careful consideration for the need of a standard will be assessed and, if so, address compliance considerations during its development. Although the standards development process is a key element to achieve the work plan, effective execution of the process will be a vital component to success.

We both wish to thank NERC's Board of Trustees and the Member Representatives Committee's Standards Process Improvement Group for their guidance and direction. We believe that this tactical plan, along with the additional enhancements contemplated regarding the Standards Committee's 2013-2015 Strategic Plan will ensure the development of timely, high quality standards ensuring bulk power system reliability, while at the same time, increasing the effectiveness of the development of reliability standards..

Sincerely,



Allen Mosher
Vice President, Policy Analysis and Reliability Standards, American Public Power Association
Chair, NERC Standards Committee



Mark Lauby
Vice President and Director of Standards,
NERC

Chapter 3 – Overview

This Plan provides:⁴

- an overview of a new strategic approach to this Plan
- the state of Standards at NERC, including
 - organization to facilitate a greater focus on production, rather than process;
 - efforts to create of a streamlined process;
 - identification of three work areas to address work needing to be accomplished;
 - application of Paragraph 81 and Results Based Standards concepts into all standards projects;
 - addressing compliance concerns;
- status updates for projects currently in development; and
- discussion of the future prioritization of standards development work.

This Plan is intended to project NERC's standards work expected for the 2013-2015 time horizon. Other unforeseen priorities may arise that will necessitate deviations in the future. Similarly, the estimated times listed for project completion may change based on unforeseen complexity emerging during the development of the standard. Hence, this Plan should be reviewed in context; it is a bold, new plan and is subject to change. However, the development of concise and clear world-class body of standards will continue to be the goal throughout the execution of these projects.

New Approach to the Development Plan

This Plan takes a bold new approach to standards development in that it completes ongoing and required work in a manner that transforms the current body of standards into an evolved body of world-class reliability standards that are effective, clear and concise.

Although some Version 0 Reliability Standards have been modified in response to regulatory directives, in many cases these changes have not been comprehensive. Additionally, clear and consistent compliance assessment remains a concern of industry stakeholders, and exerts pressure on standards development resources through the introduction of requests for interpretation and delays in reaching consensus on standards. This Plan addresses these challenges as described below.

⁴ In addition to the NERC Standards staff maintains a complete, updated set of Standards information on the NERC website, which can be found at www.nerc.com.

The strategic changes in the 2013-2015 Reliability Standards Development Plan (Plan) strive to resolve these challenges, while, at the same time, reach a steady-state for standards development. These changes will require disciplined project management, streamlining the standards development process, suitably equipped standards drafting teams, and project management plans with clearly articulated milestones and deliverables.

As new work is undertaken, careful consideration of the need for a standard will be performed. If a standard is needed, compliance considerations will be addressed during standard development. Although the role of the Reliability Issues Steering Committee (RISC) is still being defined, it is anticipated that the NERC standards program will receive input from the RISC on the need for a standard that addresses a high-risk reliability issue. Further, RISC may also be the triage body that determines whether an issue should be addressed through the creation of standard or by another solution.

In total, the enhancements to the standards development process and the launching of the RISC will bring an improved discipline to the development of reliability standards. This discipline is expected to create greater certainty around the volume of work. Further, specific to the near-term work, in 2013, three major areas of work will be addressed:

- **Projects** - Current projects must be completed and new projects that either support high-risk reliability issues or emerging issues must be conducted in an efficient manner
- **Reviews** – Five-year reviews must be conducted on standards that are due for review and have not yet been revised through other standards development projects
- **Directives** - FERC directives must be addressed and the resulting revised standards filed

There are two major initiatives will be applied across the three major work areas during their completion:

- Paragraph 81 concepts
- Results Based Standards⁵

NERC Standards' Staff Reorganization

In late 2012, the NERC standards department evaluated the 2012 organization and determined changes were required to refocus resources on the production of standards, rather than executing and monitoring process. In October, the department was realigned into three teams of standards developers and one team focused on information management.

By creating teams of standards developers, the workload may be allocated by broad category to each of the teams. Each team will have one specific high level goal:

- Resolve directives through a process similar to the Paragraph 81, Phase I standards development project or the Omnibus enforcement filings

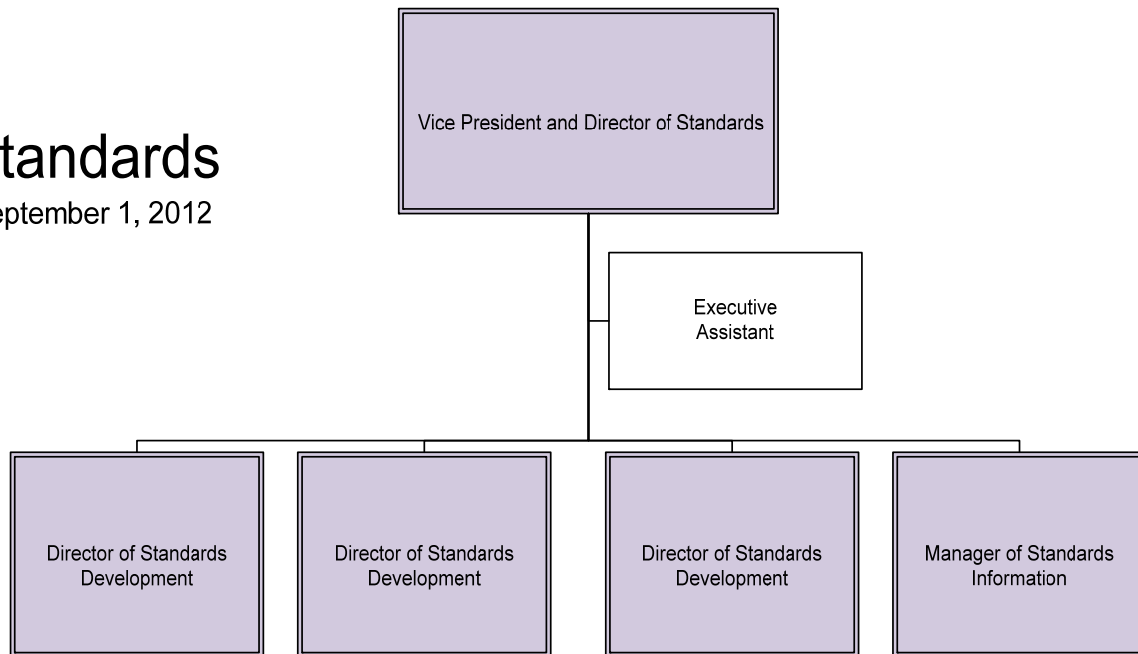
⁵ NERC staff and the SC are working together to implement drafting principles to ensure that standard drafting teams apply these two major initiative across the three major work areas.

- Conduct the required five-year reviews for current standards
- Oversee emerging issue projects and the completion of remaining open projects

These teams will closely coordinate with each other to ensure a balance in workload and expertise is created to address each of these three major work areas.

Standards

September 1, 2012



Streamlined Process

NERC's vision for a successful ERO includes a standards development process that produces standards in a timely manner considering the technical expertise of industry, provides transparency into how compliance will be assessed and ensures consistency in the audit process. At its February 9, 2012 meeting, the Board requested the assistance of the Member Representatives Committee (MRC) to provide policy input, and a proposed framework, for specific improvements to the standards development process. The MRC Chair and Vice Chair invited several members of the MRC, two NERC Board members, the NERC CEO, and the SC Chair – a group collectively known as the Standards Process Input Group (SPIG) – to join with them as participants in developing recommendations to improve the standards development in the following key areas:⁶

- Clarity on the reliability objectives, technical parameters, scope, and the relative priority of the standards project
- The drafting process (developing the specific technical content of the standard)

⁶ The recommendations can be located on the [Standard Processes Manual Revisions to Implement SPIG Recommendations project page](#) on the NERC website.

- Standards project management and workflow
- Formal balloting and commenting

Based on input from the stakeholders, the SPIG made five recommendations to modify the way NERC develops reliability standards:

1. **American National Standards Institute (ANSI):** NERC should continue to meet the minimum requirements of the ANSI process to preserve ANSI accreditation.
2. **Reliability Issues Steering Committee (RISC):** The NERC BOT is encouraged to form a RISC to conduct front-end, high-level reviews of nominated reliability issues and direct the initiation of standards projects or other solutions that will address the reliability issues.
3. **Interface with Regulatory and Governmental Authorities:** The NERC BOT is encouraged to task NERC management, working with a broad array of Electric Reliability Organization resources (e.g., the MRC, technical committees, Regional Entities, trade associations, etc.) to develop a strategy for improving the communication and awareness of effective reliability risk controls to increase input and alignment with state, federal, and provincial authorities.
4. **Standards Product Issues:** The NERC BOT is encouraged to require that the standards development process address the use of results-based standards; cost effectiveness of standards and standards development; alignment of standards requirements/measures with Reliability Standards Audit Worksheets (RSAWs); and the retirement of standards no longer needed to meet an adequate level of reliability.
5. **Standards Development Process and Resource Issues:** The NERC BOT is encouraged to require the standards development process to be revised to improve timely, stakeholder consensus in support of new or revised reliability standards. The BOT is also encouraged to require standard development resources to achieve and address formal and consistent project management and efficient formation and composition of standard drafting teams.

The Reliability Issues Steering Committee (RISC) (Recommendation 2) has been established. This committee will be tasked with identifying high risk reliability issues and may request technical research from one or more of the NERC committees and subsequently determine a direction to mitigate the risk. These solutions may result in the creation of a standard, or, alternatively, they may result in guidance documents, an alert, or other responsive action.

The SC was specifically charged with addressing SPIG Recommendations 1, 4, and 5. Since May of 2012, sub-teams of the Standards Committee Process Subcommittee (SCPS), supported by NERC standards and legal staff, have developed proposed revisions to the Standard Processes Manual (SPM) and associated changes to Section 300 of NERC's Rules of Procedure (ROP), which are now under industry review. As of the drafting of this document, changes to the SPM

in response to the SPIG recommendations, are posted for industry comment and continue to move forward.

Subsequently, at the November 2012 Board meeting, the Board issued a resolution that the Electric Reliability Organization must move forward to develop a body of high-quality, results-based standards and called for action in four areas, with reports due to the Board at the February 2013 meeting. The four areas for action are:

- The SC and standard development teams should be accountable to the Board while developing and maintaining high-quality reliability standards in a timely manner and further enabling the ERO to respond to reliability priorities, and the Standards Committee shall modify its governance, structure and scope to enable such accountability;
- Standard drafting teams should be staffed with a small number of subject matter experts that includes competencies in technical, legal, drafting, compliance, and project management;
- The SC should manage workflow and process to ensure the timely development of high-quality, results-based reliability standards; and
- The SC and NERC staff should work with the Reliability Issues Steering Committee (RISC) to jointly develop viable work plans to dispense with work that is no longer pertinent to reliability and aggressively pursue work that will result in a body of high-quality reliability standards that will address reliability risks to the bulk power system.

Additional changes are being considered by the SC in response to the Board's resolution, and the SC will present its recommendations at the February 2013 Board meeting.

The Identification of Three Work Areas

The evaluation of the work necessary to achieve a stable body of effective, concise and clear standards identifies three general work areas:

1. **Projects** - Current projects must be completed in a timely manner to resolve the identified reliability concerns that created the projects. This team will address the projects that were included in the 2012-2014 RSDP and the coordination plan to bring these projects to completion, along with projected timelines for the completion of each project. This work area also includes new projects that either support high risk reliability issues or other emerging issues. Completion of these projects will include application of the Results-Based Standards drafting concepts and Paragraph 81 concepts. In the event that a given project is sufficiently close to completion and applying these concepts would delay completion, the standard(s) involved would be scheduled for further review in a subsequent project to determine if additional modifications are necessary.
2. **Reviews** – Five-year reviews must be conducted on standards that are due for review and have not yet been revised through other standards development projects. A comprehensive review will include application of the Results Based Standards drafting

concepts and Paragraph 81 concepts, and will also include a review of the each standard in relation to other standards to eliminate duplicative requirements.

3. **Directives** - FERC directives across all orders must be addressed and the results filed. Completion of these projects will include application of the Results-Based Standards drafting concepts and Paragraph 81 concepts. In the event that a drafting team or industry determines that the directive is no longer optimal for reliability (whether it be due to application of the Paragraph 81 standards, that the directive has been overcome by events, or for another reliability-based reason) , a determination may be to make a filing with FERC to resolve the directive.

Each of these work areas have dedicated NERC staff, who will coordinate on a regular basis to ensure the interdependencies between these efforts are considered and addressed. Allocation of work has been determined in coordination with SC based on the requirement for each project. For example, a standard/requirement that has a single directive associated with it that is included in an ongoing project is assigned to the Projects team.

Application of Paragraph 81 and Results Based Standards Concepts

Transitioning the current body of standards into a clear, concise and effective body will require a comprehensive application of the following concepts: 1) elimination or revision of requirements that are duplicative or do little to improve reliability (the Paragraph 81 concept, which addresses the conciseness of the body of standards); and 2) ensuring that each standard, or family of standards, contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved (the “Results Based Standards” concept). A results-based requirement follows the form *“Which functional entity/ies, under what circumstances, shall do what for what reliability outcome.”* The results-based concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

Addressing Compliance Assessment Concerns

Based on feedback from stakeholders, there is a key link between Reliability Standards development and compliance considerations. A number of improvements are being considered to bridge this ongoing gap.

1. Integration of Internal Controls with Standards

The ERO compliance monitoring program is transitioning to support reliability on a forward-looking basis with greater consideration and reliance on internal controls, as opposed to the current construct which focuses on the rearward-looking process of reviewing potentially significant amounts of evidence over the entire audit period. This is a shift from the current construct in which all violations, regardless of the risk created to the reliability of the bulk power system or when the violation occurred, must be processed.

This new approach has been piloted in 2012 on two standard development projects in 2012: COM-003 and CIP version 5.

2. Concurrent Development of Compliance Assessment Tools, such as Reliability Standard Audit Worksheets (RSAWs), and Standards

Another concept that has been piloted in the COM-003⁷ and the CIP version 5⁸ standards development projects is the concurrent development of the RSAW with the standard. While RSAW development is not part of the Standards Development Process, visibility into the impact the language of the standard has on compliance assessment has improved the drafting of these reliability standards.

Both of these approaches are still being piloted, with encouraging results to date. They will continue to be explored throughout 2013.

⁷ Project 2007-02 Operating Personnel Communications Protocols – COM-003

⁸ Project 2008-06 – Cyber Security – Order 706

Chapter 4 – Production Status

The 2012-2014 Reliability Standards Development Plan (2012-2014 RSDP) identified 14 active projects to be conducted over the three year period, of which 8 have either been completed or will be completed by 2012 year end.

Projects that were listed in the 2012-2014 RSDP as active:

Completed (8)

- 2006-06 Reliability Coordination
- 2007-03 Real-time Transmission Operations
- 2007-07 Vegetation Management
- 2007-17 Protection System Maintenance and Testing
- 2008-06 Cyber Security – Order 706
- 2009-01 Disturbance and Sabotage Reporting
- 2010-07 Generator Requirements at the Transmission Interface
- 2010-17 Definition of Bulk Electric System

To be completed (6)

- 2007-02 Operating Personnel Communication Protocols (schedule completion: second Quarter or Q2 of 2013)
- 2007-06 Protection System Coordination (schedule completion: Q2 of 2013)
- 2007-09 Generator Verification (schedule completion: Q2 of 2013)
- 2007-12 Frequency Response (May 31, 2013 filing deadline)
- 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves (May 31, 2013 filing deadline for BAL-012; target completion for remaining standards Q2 of 2013)
- 2010-05.1 Phase 1 of Protection Systems: Misoperations (schedule completion: Q1 of 2014)

In addition to projects listed in the 2012-2014 RSDP, the following projects began development and are currently active (5):

- 2006-02 Assess Transmission Future Needs and Develop Transmission Plans (Filed Oct 2011)
- 2010-11 TPL Table 1, Footnote B (schedule completion: Q2 of 2013)
- 2010-13.2 Phase 2 of Relay Loadability: Generation
- 2013-02 Paragraph 81
- Definition of Adequate Level of Reliability

NERC and the Regional Entities also completed development of another 12 projects not listed in the 2012-2014 RSDP:

- Project 2008-10 Interpretation of CIP-006-1 for Progress Energy
- Project 2009-19 BAL-002-0 R4 and R5 (NWPP Reserve Sharing Group)
- Project 2009-22 Interpretation of COM-002-2 for the IRC
- Project 2009-26 — Interpretation of CIP-004-1 for WECC
- Project 2010-INT-01 Rapid Revision of TOP-006-2 for Florida Municipal Power Pool
- Project 2011-INT-01 Interpretation of MOD-028 for Florida Power & Light Company (Rapid Revision Standard)
- Reliability Standard BAL-002-WECC-2 - Contingency Reserve
- Reliability Standard PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding
- Reliability Standard PRC-006-SERC-01 – Automatic Underfrequency Load Shedding Requirements
- Reliability Standard PRC-006-SPP-01 – Automatic Underfrequency Load Shedding
- Reliability Standard VAR-001-3 – Voltage and Reactive Control (WECC Regional Variance)
- Data Request for Order 754

Progress on Regulatory Directives

Since NERC became the Electric Reliability Organization (ERO), FERC has issued 44 Orders containing approximately 655 directives and guidances related to NERC Reliability Standards. Fifty-three percent of the directives (including guidances) have been resolved or will be resolved with the filing of the standards development projects that were approved by the Board in either November or December. This is a substantial increase from the 44 percent resolution rate reported in the 2012-2014 RSDP.

The chart below accounts for all outstanding directives and guidance issues remaining to be resolved.

Summary of Directives

There are currently 303 FERC directives or guidance remaining to be resolved:

- 206 are directives for specific action
- 97 are FERC guidance; each will be assessed by the standard drafting teams and tracked

Of the 206 directives for specific action:

- 84 will be completed in current projects (58 completed in 2012, 26 in 2013)
- Five are outdated or overcome by events (filing these in 2012)
- 116 are included in this 2013-2015 reliability standards development work plan, targeted for 2013 completion
- One is specific to a five- year review which will also be completed in 2013.

Expected Completion	Category	Directives	FERC Guidance	Yearly Total	Percent Complete
2012	<i>Completed with current projects</i>	58	31		
2012	<i>Outdated or overcome by events</i>	5	2	96	32%
Q1 or Q2 2013	<i>Completed with current projects</i>	26	19		
2013	<i>2013 project work plan</i>	116	39		
2013	<i>Directives for a NERC committee</i>		3		
2013	<i>Directives for 5 year reviews</i>	1	2		
2013	<i>Directives not specific to standards</i>		1	207	68%
		206	97	303	

Projects anticipated for completion in 2012 address 58 FERC directives and 31 guidance elements (shown below as directives/guidance for each project):

Board approved in November 2012

- Reliability Coordination (COM-001 and COM-002) – 11/3
- Protection System Maintenance and Testing – PRC-005-2 – 4/1
- Disturbance and Sabotage Reporting – CIP-001 and EOP-004 – 8/4

Board approved in December 2012

- Cyber Security Order 706 - 35/23

In 2013, NERC's goal is to resolve all of the outstanding directives or, if there are directives that cannot be resolved in 2013 due their complexity or the need for additional technical committee technical research, to provide a project plan to close the directives by the end of 2014.

Chapter 5 – Directives Team

As discussed above, this Plan reflects NERC’s goal to resolve all of the outstanding directives in 2013 or, if there are directives that cannot be resolved in 2013, to provide a project plan to bring those directives to closure by the end of 2014. Work was allocated across the three teams based upon an analysis of which team’s focus had the greatest impact on the standard or requirement made by NERC staff and SC representatives.⁹ The directives team will be responsible for resolving directives associated with the:

- Modeling, Data, and Analysis (MOD) standards, which are divided into three projects previously identified for future action in the 2012-2014 Reliability Standard Development Plan:
 - Project 2012-05 ATC Revisions from Order 729
 - Project 2010-03 Modeling Data
 - Project 2010-04 Demand Data,
- Personnel Performance, Training and Qualifications (PER) standards
- Voltage and Reactive (VAR) standards
- Facilities Design, Connection, and Maintenance (FAC) standards
- Glossary

Additionally, projects addressing Frequency Response and Balancing Authority Reliability-based Control (BARC) will be completed in 2013.

A high level projection for the development of these projects is included in the Action Plan provided below. A detailed project plan with development milestones will be included with the submittal of the SAR.

⁹ The work plans set forth below also rely on a streamlined standards development process that employs more informal consensus building upfront rather than consensus building solely through the comment and ballot period. This new process is being developed by the SC and NERC Staff and will be presented to the Board in February.

Action Plan for Directives Team

Priority Issue	Proposed Activity	Abstract	Deliverables	Targeted Milestones <i>Project Plans to be Developed with SAR</i>
1. Directives	MOD A – ATC/TTC/CBM <i>Project 2012-05 ATC Revisions Order 729</i>	Prepare and achieve approval on Reliability Standards for a subset of MOD standards identified in FERC Order 729 with regards to the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability and Existing Transmission Commitments.	• MOD-001 • MOD-004 • MOD-028 • MOD-029 • MOD-030	• Research Complete – 01/2013 • Informal Outreach – 04/2013 • SAR Developed – 07/2013 • Initial Comment Period/Ballot – 07/2013 • Recirculation Ballot – 09/2013 • Presented to BOT – 11/2013
	Frequency Response Directives and issues <i>Project 2007-12 Frequency Response</i>	The proposed standard would set a minimum Frequency Response obligation for each Balancing Authority, provide a uniform calculation of Frequency Response and Frequency Bias Settings that transition to values closer to natural Frequency Response, and encourage coordinated AGC operation.	• BAL-003	• Recirculation Ballot – 12/2012 • Presented to BOT – 02/2013 • Filed with FERC – 05/2013
	BARC Directives and issues <i>Project 2010-14.1 Balancing Authority Reliability-based Controls</i>	The purpose of this project is to ensure that Balancing Authorities take actions to maintain interconnection frequency with each Balancing Authority contributing its fair share to frequency control.	• BAL-012	• Initial Ballot – 01/2013 • Recirculation Ballot – 03/2013 • Presented to BOT – 05/2013 • Filed with FERC – 05/2013
	MOD B – Modeling Data <i>Project 2010-03 Modeling Data</i>	Prepare and achieve approval on Reliability Standards that requires merging, upgrading and expanding existing requirements for entities to provide data used to model the Bulk Electric System which relates to Blackout recommendations and the modeling Initiative; and to prepare and achieve approval on Reliability Standards that clearly identifies the requirements for providing data.	• MOD-010 • MOD-011 • MOD-012 • MOD-013 • MOD-014 • MOD-015	• Research Complete – 01/2013 • Informal Outreach – 01/2013 • SAR Developed – 05/2013 • Initial Comment Period/Ballot – 06/2013 • Recirculation Ballot – 09/2013 • Presented to BOT – 11/2013

Priority Issue	Proposed Activity	Abstract	Deliverables	Targeted Milestones <i>Project Plans to be Developed with SAR</i>
	MOD C – Demand Data <i>Project 2010-04 Demand Data</i>	Prepare and achieve approval on Reliability Standards that requires merging, upgrading and expanding existing requirements for entities to provide data used to model the Bulk Electric System which relates to Blackout recommendations and the modeling Initiative; and to prepare and achieve approval on Reliability Standards that clearly identifies the requirements for providing data.	• MOD-016 • MOD-017 • MOD-018 • MOD-019 • MOD-020 • MOD-021	• Research Complete – 03/2013 • Informal Outreach – 03/2013 • SAR Developed – 06/2013 • Initial Comment Period/Ballot – 07/2013 • Recirculation Ballot – 09/2013 • Presented to BOT – 11/2013
	PER Directives <i>Project 2010-01 Support Personnel Training</i>	Prepare and achieve approval on Reliability Standards that require the use of a systematic approach to determining training needs of generator operators and operations planning and support staff with a direct impact on the reliable operations of the bulk power system.	• PER-002 • PER-005	• Research Complete – 04/2013 • Informal Outreach – 04/2013 • SAR Developed – 06/2013 • Initial Comment Period/Ballot – 07/2013 • Recirculation Ballot – 09/2013 • Presented to BOT – 11/2013
	FAC Directives	Collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results to develop a standard that would apply to both federal and non-federal lands.	• Outage data collected by the appropriate party, whether it is TADS, Region or NERC • Possible new standard	• Research Complete – 04/2013 • Informal Outreach – 04/2013 • SAR Developed – 06/2013 • Initial Comment Period/Ballot – 07/2013 • Recirculation Ballot – 09/2013 • Presented to BOT – 11/2013
	NERC Glossary <i>Project 2012 – 08 Definitions</i>	To achieve approval on the NERC Glossary in order to respond to requests for clarification.	• Add statutory definitions of Bulk Power System, Reliable Operation, and Reliability Standard to the NERC Glossary • Modify existing definition of Transmission Operator and Generator Operator • Revise Functional Model to avoid confusion with the NERC Glossary	• SAR Developed – 2012 • Initial Comment Period/Ballot – 2012 • Successive Comment Period – 03/2013 • Recirculation Ballot – 08/2013 • Presented to BOT – 11/2013

Priority Issue	Proposed Activity	Abstract	Deliverables	Targeted Milestones <i>Project Plans to be Developed with SAR</i>
	VAR Directives <i>Project 2008-01</i>	Prepare and achieve approval on the existing VAR-001 and VAR-002 Reliability Standards to be more specific in defining voltage and reactive power schedules. Consideration should be given to adding a requirement for the Reliability Coordinator to monitor and take action if reactive power falls outside identified limits.	• VAR-001 • VAR-002	• Informal Outreach – 02/2013 • SAR Developed – 06/2013 • Initial Comment Period/Ballot – 07/2013 • Recirculation Ballot – 09/2013 • Presented to BOT – 11/2013
	Close out one Registry Directive	Consider whether NERC should register demand side aggregators if the loss of their load shedding capability, for reasons such as a cyber incident, would affect the reliability or operability of the BPS.	• A consideration of whether the Compliance Registry needs to be updated • A consideration of whether the definitions of Demand Response and Direct Load Control need to be added to the NERC Glossary	• Informal Outreach – 01/2013 • SAR Developed – 03/2013 • Initial Comment Period/Ballot – 03/2013 • Recirculation Ballot – 04/2013 • Presented to BOT – 11/2013

Chapter 6 – Five-Year Reviews

Within the time horizon of this plan, all Version 0 standards that have not been significantly revised or retired will undergo a comprehensive review to determine what, if any, changes are needed to improve the clarity and conciseness of the standards. This will include applying the Paragraph 81 and Results-Based Standards concepts, in addition to reviewing the standards to ensure that each is technically sound given current technologies and system conditions. Several standard families will be reviewed comprehensively by the Reviews team:

- Emergency Preparedness and Operations (EOP) Standards
- Facilities Design, Connection, and Maintenance (FAC) Standards
- Interchange Scheduling and Coordination (INT) Standards
- Interconnection Reliability Operations and Coordination (IRO) Standards
- Nuclear (NUC) Standard

In addition, coordination with other standard development teams will ensure that standards due for five-year review are reviewed on or before the date that it is due for a five-year review.

Finally, the action plan in the table below reflects that the standards developers on the review team have responsibility for several on-going projects as well as a potential emerging issue (geomagnetic disturbance mitigation).

Action Plan for Five-Year Reviews Team

Priority Issue	Proposed Activity	Abstract	Deliverables	Targeted Milestones <i>Project Plans to be Developed with SAR</i>
	Project 2007-09 Generator Verification		- MOD-024 - MOD-025 - MOD-026 - MOD-027 - PRC-019 - PRC-024	- Recirculation Ballots – 01/2013 - Presented to BOT – 2/2013
2. Reviews	Project 2008-12 Coordinate Interchange Standards	Revise the set of Coordinate Interchange standards to 1) ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange, 2) to address the Interchange Subcommittee's concerns related to the Dynamic Transfers and Pseudo-ties, and 3) to address previously identified stakeholder comments and applicable directives from Order 693.	Revise: - INT-001-3 - INT-003-3 - INT-004-2 - INT-005-3 - INT-006-3 - INT-007-1 - INT-008-3 - INT-009-1 - INT-010-1	- Informal outreach and SAR revised – Q1 2013 - Initial Ballot – Q2 2013 - Recirculation Ballot – Q3 2013 - Presented to BOT – 11/2013
	Project 2009-03 Emergency Operations	Several EOP standards may be merged into a single standard. There are some requirements in IRO-001 that may be improved and merged into the new EOP standard. In addition, a comprehensive review will be conducted of the entire EOP family of standards.	Review/Revise: - 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	- Informal outreach and SMEs assembled for comprehensive review – Q1 2013 - Review results/assessment posted for industry comment – Q1 2013 - Comments reviewed; SAR revised, SDT appointed – Q2 2013 - Initial Ballot – Q2 2013 - Successive Comment Period – Q3 2013 - Recirculation Ballot – Q4 2013 - Present to BOT – 2/2014
	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Create new or revised standards to establish requirements for the monitoring and analysis capabilities provided to System Operators to support Real-time System Operations. The project will address availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management.	New Standard(s)	- Repopulate SDT – Q4 2012 - Informal outreach and review/respond comments on white paper posted in 2011 – Q2 2013 - Initial Ballot – Q3 2013 - Recirculation Ballot – Q4 2013 - Present to BOT – 2/2014

Priority Issue	Proposed Activity	Abstract	Deliverables	Targeted Milestones <i>Project Plans to be Developed with SAR</i>
	Project 2010-11 TPL Footnote 'b'	FERC Order RM06-16-009 which required the ERO to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010. The SAR provides a revision to TPL Table 1 footnote 'b' to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004 so while the FERC Order was for TPL-002, the change is reflected in all 4 standards.	Revised Footnote to be included in: • TPL-001 • TPL-002 • TPL-003 • TPL-004	• Successive Ballot – Q4 2012 • Recirculation Ballot – 1/2013 • Presented to BOT – 2/2013
	Project 2010-17 Definition of Bulk Electric System	This project will revise the definition of Bulk Electric System (BES) to address various Federal Energy Regulatory Commissions (FERC) concerns the definition must be modified to encompass all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. These concerns have been identified in FERC Order 693 issued on March 16, 2007 and in Order 743 issued on November 18, 2010 (Order 743). The project will also consider additional modifications (beyond those established in the regulatory directives) to improve clarity, to reduce ambiguity and to establish consistency across all Regions in distinguishing between BES and non-BES Elements and Facilities.	Revise: Definition of <i>Bulk Electric System</i>	• Initial Ballot – Q1 2013 • Successive Ballot – Q2 2013 • Recirculation Ballot – Q3 2013 • Presented to BOT – 2/2014

Priority Issue	Proposed Activity	Abstract	Deliverables	Targeted Milestones <i>Project Plans to be Developed with SAR</i>
	Project 2012-09 IRO Review This project may incorporate Phase 2 of Project 2006-06 Reliability Coordination.	This project will conduct a comprehensive review of the IRO set of standards.	Various IRO standards	• Informal outreach and SMEs assembled for comprehensive review – Q1 2013 • Review results/assessment posted for industry comment – Q1 2013 • Comments reviewed; review results posted – Q2 2013 • SAR developed, SDT appointed – Q2 2013 • Initial Ballot – Q3 2012 • Recirculation Ballot – Q4 2013 • Presented to BOT – 2/2014
	Project 2012-13 NUC Review	This project will conduct a comprehensive review of the NUC-001 standard.	NUC-001	• Informal outreach and SMEs assembled for review – Q3 2013 • Review completed – Q1 2014 If review indicates the need: • SAR developed – Q1 2014 • Initial ballot – Q3 2014 • Recirculation ballot – Q3/4 2014 • Presented to BOT – 11/2014
	Project 2013-03 Geomagnetic Disturbance Mitigation Measures	TBD	New or Revised Standard TBD	• Informal outreach – Q4 2012/Q1 2013 • SAR Completed – Q1 2013 • Initial Ballot (Phase 1) – Q2 2013 • Successive Comment Period (Phase 1) – Q3 2013 • Initial Ballot (Phase 2) – Q2 2013 • Recirculation Ballot (Phase 1) – Q3 2013 • Recirculation Ballot (Phase 2) – Q4 2013 • Presented to BOT (Phase 1) – 11/2013 • Presented to BOT (Phase 1) – 1/2014

Priority Issue	Proposed Activity	Abstract	Deliverables	Targeted Milestones <i>Project Plans to be Developed with SAR</i>
	Project 2010-02 Connecting new facilities to the grid	This project will ensure that all of the elements that should be addressed when a new facility is connected to the grid are included in the revised standards. In addition, a comprehensive review of FAC-001 and -002 will be done to address suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 submitted by stakeholders, other drafting teams, and FERC staff.		• Informal outreach and SAR revised – Q1 2013 • Initial Ballot – Q2 2013 • Recirculation Ballot – Q3 2013 • Presented to BOT – 11/2013

Chapter 7 – Projects and Emerging Issues

Another key focus is the completion of current standard development in an efficient and timely manner. It is imperative that these projects be completed to resolve the identified reliability concerns that created the need for the projects. The Standards Committee and NERC staff has dedicated resources to address the projects that were included in the 2013-2015 RSDP to develop a coordinated plan to bring these projects to completion. Completion of these projects will include application of the Results-Based Standards drafting concepts and Paragraph 81 concepts. In the event that a given project is sufficiently close to completion and applying these concepts would delay completion, the standard(s) involved would be scheduled for further review in a subsequent project to determine if additional modifications are suggested.

Action Plan for Projects Team

Priority Issue	Project Number	Project Name	Abstract	Deliverables	Targeted Milestones <i>Project Plans to be Developed with SAR</i>
Completion of Projects/Emerging Issues	2007-02	Operating Personnel Communication Protocols	This standard will require the use of specific communication protocols, especially for communications during alerts and emergencies. The standard will be applicable to transmission operators, balancing authorities, reliability coordinators, generator operators and distribution providers. Requirements will include protocols for communicating changes to real-time operating states and protocols for issuing and responding to Operating Instructions.	• COM-003	• Recirculation Ballot – 01/2013 • Presented to BOT – 02/2013
	2007-06	System Protection Coordination	Review PRC-001-1 to assure that Protection System application and performance issues are coordinated among all related entities. It will ensure the applicable entities within the standard correctly reflect the functional responsibilities, as described in the NERC Functional Model. The project will also incorporate other general improvements, address directives received from ERO regulatory authorities, and consider the observations and recommendations developed by the NERC SPCTF.	• PRC-001 • PRC-027	• Recirculation Ballot – 02/2013 • Presented to BOT – 05/2013

	2007-11	Disturbance Monitoring	This project establishes and clarifies requirements for the installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models.	• PRC-002 • PRC-018	• Initial Comment Period/Ballot – 06/2013 • Recirculation Ballot – 09/2013 • Presented to BOT – 11/2013
	2007-17.2	Protection System Maintenance and Testing	This project will modify the PRC-005 standard to ensure that reclosing relays are maintained and tested.	• PRC-005	• Initial Comment Period/Ballot – 07/2013 • Recirculation Ballot – 09/2013 • Presented to BOT – 11/2013
	2010-05.1	Phase 1 of Protection Systems: Misoperations	This project addresses a key element for Bulk Electric System (BES) reliability: the correct performance of Protection Systems. Monitoring BES Protection System events to identify and correct the root causes of Misoperations will improve overall Protection System performance.	• PRC-003 • PRC-004	• Successive Ballot – 02/2013 • Recirculation Ballot – 04/2013 • Presented to BOT – 05/2013
	2010-13.2	Generator Relay Loadability	The project will draft a new standard to address generator relay loadability.	• PRC-025	• Initial Comment Period/Ballot – 01/2013 • Successive Ballot – 04/2013 • Recirculation Ballot – 06/2013 • Presented to BOT – 8/2013
	2013-01	Cold Weather Preparedness	To require GO/GOPs to report generating unit capabilities based on anticipated winter weather using criteria developed by the standard drafting team using stakeholder input. GO/GOPs must ensure winter weather preparation plans are created, maintained, implemented and monitored as appropriate to help ensure generating units can operate to the criteria developed above. The plans shall include appropriate annual winterization measures.	• New Standard	• SAR Developed – 02/2013 • Initial Comment Period/Ballot – 07/2013 • Recirculation Ballot – 09/2013 • Presented to BOT – 11/2013

	2008-02	Undervoltage Load Shedding	To improve the existing standards on Under Voltage Load Shedding (UVLS) to include criteria for Under Voltage Load Shedding programs such that the programs work as intended to shed load when needed and prevent voltage collapse and voltage instability in the Bulk Electric System.	• PRC-010 • PRC-022	• Initial Comment Period/Ballot – 09/2013 • Recirculation Ballot – 12/2013 • Presented to BOT – 02/2014
	2010-16	Definition of System Operator	This project proposes revising the existing definition of System Operator to remove the inclusion of “Generator Operator.” This change would avoid the confusion caused by the use of the term “System Operator” in reference to the real-time operating personnel who work for Generator Operators. Inaccurate definitions results in misconception of responsibilities and expectations which can negatively impact reliability	• Revised definition	• Initial Comment Period/Ballot – 03/2013 • Successive Ballot – 05/2013 • Recirculation Ballot – 06/2013 • Presented to BOT – 8/2013
	2010-14.2	Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent	This project will consider the Time Error Correction, AGC, and Inadvertent Accounting standards to determine what changes, if any, are necessary to ensure the standards are clear and unambiguous. <i>This project will be reviewed to determine if it is still necessary, and if so, what the appropriate scope of the project is.</i>	Revise: • BAL-004-0 • BAL-005-0.1b • BAL-006-2	• Review of Project – Q2 2013 • Revised scope, SAR – Q3 2013

Chapter 8 – Conclusion

This ambitious but achievable plan represents several significant shifts from NERC's prior year Reliability Standards Development Plan. Many of the projects that were slated for work in future years have been moved up, while other projects have been proposed as candidates for consolidation or, in some cases, dismissal. The goal of this three-year plan is to transition from the current set of reliability standards to a world class body of reliability standards that are clear, concise, and will ensure the reliability of the bulk power system in North America.

Successful execution of the 2013-2015 RSDP will require a concerted effort by NERC and industry stakeholders, and a reliance on the standards development process as an enabler of success. NERC and the NERC Standards Committee are committed to meet the goals of this plan.

Appendix 1 – Research

NERC standards staff and the SC are working with the NERC technical committees for the completion of technical research prepared for the below projects. The chart includes an anticipated start date for the technical committees to be able to begin the research.

Committee	Project	2012-2014 RSDP Estimated Research Start
Planning Committee	Oder 754 Data Request	Complete
Planning Committee	Project 2007-12 Frequency Response (ACTIVE)	Complete
Planning Committee	Project 2009-07 Reliability of Protection Systems	Data collection begins in Q3 2013 and will be fully collected by Sept 2014
Planning Committee	Project 2012-06 Generator Capabilities	Q1 2013
Operating Committee	Project 2009-04 Phasor Measurements	Q1 2014
Planning Committee	Project 2012-04 Protection System Commissioning Testing	Q1 2012
Operating Committee	Project 2012-01 Equipment Monitoring and Diagnostic Devices	Q2 2013
Operating Committee	Project 2010-02 Connecting New Facilities to the Grid	Q2 2015
Operating Committee	Project 2010-01 Support Personnel Training	Q3 2012
Planning Committee (SAMS with support from Model Validation WG)	Project 2010-03 Modeling Data	complete
Planning Committee (RAS)	Project 2010-04 Demand Data	Q1 2013
Planning Committee	Project 2010-05.2 Phase 2 of Protections Systems: SPS and RAS	Q4 2012
Planning Committee (SPCS)	Project 2010-13-3 Phase 3 of Relay Loadability: Stable Power Swings	Q4 2014
Planning Committee	Project 2010-17 Definition of BES Phase 2(ACTIVE)	Q4 2012

Appendix 2 – Assignment of Projects or Standards

	Factors					Assignment		
Standard Number for FERC Approved Stds	Directive	Guidance	Existing/ Future Std Projects	P81	Five Year Review	Directives Team	5-Year Review Team	Projects and Emerging Issues Team
BAL-001-0.1a			X	X				X
BAL-002-0	x		X					X
BAL-002-1								X
BAL-STD-002-0								
BAL-003-0.1b	x		X					X
BAL-004-0	X		X	X			X	
BAL-004-WECC-01	X	X						
BAL-005-0.1b	X	X	X	X	X		X	
BAL-006-2	X		X	X	X		X	
BAL-502-RFC-02								
CIP V5 Standards			X	X				
COM-001-1.1	X		X	X				
COM-002-2		X	X					
COM-003-1			X					
EOP-001-0b	X	X	X	X			X	
EOP-001-2b			X				X	
EOP-002-3	X		X	X			X	
EOP-003-1		X	X				X	
EOP-004-1		X		X			X	
EOP-005-1				X			X	
EOP-005-2				X			X	
EOP-006-1							X	
EOP-006-2							X	
EOP-008-0				X			X	
EOP-008-1				X			X	
EOP-009-0							X	
FAC-001-0			X	X			X	
FAC-002-1	X	X	X	X			X	
FAC-003-1				X		X		
FAC-008-1				X				
FAC-008-3				X				
FAC-009-1								
FAC-010-2.1				X	X			
FAC-011-2				X	X			
FAC-012-1								
FAC-013-1				X	X			
FAC-013-2								
FAC-014-2					X			

Standard Number for FERC Approved Stds	Factors						Assignment			
	Directive	Guidance	Existing/ Future Std Projects	P81	Five Year Review		Directives Team	5-Year Review Team	Projects and Emerging Issues Team	
FAC-501-WECC-1										
INT-001-3		X	X	X	X			X		
INT-004-2			X	X	X			X		
INT-005-3			X	X	X			X		
INT-006-3	X		X	X				X		
INT-007-1			X	X				X		
INT-008-3		X	X	X				X		
INT-009-1	x		X	X				X		
INT-010-1	x		X	X				X		
IRO-001-1.1		X	X	X				X		
IRO-002-2		X		X				X		
IRO-003-2	x		X					X		
IRO-004-2		X		X				X		
IRO-005-3a	X			X				X		
IRO-006-5		X			X			x		
IRO-006-EAST-1										
IRO-006-WECC-1										
IRO-008-1					X			X		
IRO-009-1					X			X		
IRO-010-1a				X	X			X		
IRO-014-1				X				X		
IRO-015-1				X				X		
IRO-016-1								X		
MOD-001-1a	x	X	X	X	X		X			
MOD-004-1	x		X	X	X		X			
MOD-008-1			X	X	X		X			
MOD-010-0	x		X	X			X			
MOD-012-0	x		X	X			X			
MOD-016-1.1	X	X	X	X			X			
MOD-017-0.1	X		X	X			X			
MOD-018-0	x		X	x			X			
MOD-019-0.1	x	X	X	X			X			
MOD-020-0	X		X	X			X			
MOD-021-1	x	X	X	X			X			
MOD-028-1	X	X	X	X	X		X			
MOD-029-1a	X		X	X	X		X			
MOD-030-2	X		X	X	X		X			
NUC-001-2					X					
PER-001-0.1				X						
PER-002-0	X	X					X			
PER-003-0										
PER-004-1										
PER-004-2										
PER-005-1	X				X		X			
PRC-001-1	X		X						X	
PRC-002-NPCC-01									X	

Standard Number for FERC Approved Stds	Factors					Assignment		
	Directive	Guidance	Existing/ Future Std Projects	P81	Five Year Review	Directives Team	5-Year Review Team	Projects and Emerging Issues Team
PRC-004-1a								X
PRC-004-2a		X	X					X
PRC-004-WECC-1				X				
PRC-005-1a	X			X				X
PRC-005-1b	X			X				X
PRC-007-0				X				X
PRC-008-0				X				X
PRC-009-0				X				X
PRC-010-0	X		X	X				X
PRC-011-0				X				X
PRC-015-0			X	X				X
PRC-016-0.1			X	X				X
PRC-017-0				X				X
PRC-018-1			X	X				X
PRC-021-1				X				X
PRC-021-1								
PRC-022-1	X		X	X				X
PRC-023-1	X	X		X				X
TOP-001-1a	X			X			X	
TOP-002-2b	X			X			X	
TOP-003-1				X			X	
TOP-004-2							X	
TOP-005-2a				X	X		X	
TOP-006-2				X			X	
TOP-007-WECC-1							X	
TOP-008-1				X			X	
TPL-001-0.1			X	X				
TPL-002-0b		X	X	X				
TPL-003-0a				X				
TPL-004-0				X				
TPL-005			X					
VAR-001-2	X	X	X	X	X	X		
VAR-002-1.1b	X		X	X		X		
VAR-002-WECC-1								
Non FERC-approved								
FAC-005-WECC-1 AND PRC-004-WECC-1	X							
Glossary	X	X				X		
All MODs	X					X		
MOD-013	X		X			X		
MOD-014	X		X			X		
MOD-015	X		X			X		
MOD-024	X	X				X		
MOD-025	X	X				X		
PRC-002	X		X					X

	Factors					Assignment		
Standard Number for FERC Approved Stds	Directive	Guidance	Existing/ Future Std Projects	P81	Five Year Review	Directives Team	5-Year Review Team	Projects and Emerging Issues Team
PRC-003	X							X
PRC-006	X			X				X
PRC-012	X		X					X
PRC-013	X		X					X
PRC-014		X	X					X
PRC-003 WECC				X				X
Existing Project for New Stds, future projects, emerging issues								
MOD-025-2, MOD-026-1, MOD-027-1 PRC-019-1, and PRC-024-1			X					X
EOP-004-2			X					
PRC-025, phase 2			X					X
IRO-006-WECC-2			X					X
COM-003			X					X
GMD			X				X	
BES definition			X				X	
Glossary	X		X			X		
BAL-012			X					X
BAL-013			X					X
MOD-011			X			X		

Appendix 3 – Project Summaries

The following are detailed summaries of the projects discussed earlier within this plan.

IN DEVELOPMENT PROJECTS TEAM

Project 2007-02 Operating Personnel Communication Protocols

Summary:

This standard will require the use of specific communication protocols, especially for communications during alerts and emergencies. The standard will be applicable to transmission operators, balancing authorities, reliability coordinators, generator operators and distribution providers. Requirements will include protocols for communicating changes to real-time operating states and protocols for issuing and responding to operating directives.

Standards affected: COM-003

IN DEVELOPMENT PROJECTS TEAM

Project 2007-06 System Protection Coordination

Summary:

This project is reviewing PRC-001-1 to assure that Protection System application and performance issues are coordinated among all related entities. It will ensure the applicable entities within the standard correctly reflect the functional responsibilities, as described in the NERC Functional Model. The project will also incorporate other general improvements, address directives received from ERO regulatory authorities, and consider the observations and recommendations developed by the NERC Systems Protection and Controls Task Force (SPCTF). As necessary, the project will coordinate the transfer of monitoring-related requirements to other standards as appropriate through coordination with project 2006-06 Reliability Coordination.

Standards affected: PRC-001, PRC-027 (New)

**IN DEVELOPMENT
PROJECTS TEAM**

Project 2007-09 Generator Verification

Summary:

This project will create or modify standards to ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions. It also will ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

Standards affected: MOD-024, MOD-025, MOD-026, MOD-027, PRC-019, PRC-024

**IN DEVELOPMENT
PROJECTS TEAM**

Project 2007-11 Disturbance Monitoring

Summary:

This project establishes and clarifies requirements for the installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. The project will review PRC-002 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to or contained within the disturbance monitoring program documentation. The project will then determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

Standards affected: PRC-002, PRC-018

**IN DEVELOPMENT
PROJECTS/DIRECTIVES TEAM**

Project 2007-12 Frequency Response

Summary:

Purpose:

This project will modify the BAL-003 Standard to require sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds. It also will ensure the standard provides consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

Standards affected: BAL-003

**IN DEVELOPMENT
PROJECTS TEAM**

Project 2007-17.2 Protection System Maintenance and Testing

Summary:

This project will modify the PRC-005 standard to ensure that reclosing relays are maintained and tested.

Standards affected: PRC-005

**IN DEVELOPMENT
DIRECTIVES TEAM**

Project 2008-01 Voltage and Reactive Planning and Control

Summary:

This project will revise the VAR Standards to require that appropriate functional entities develop and coordinate voltage and reactive planning and operating criteria to ensure that there are sufficient reactive resources, and voltage and reactive margins, to manage the risk of voltage instability. The project will also address the FERC directives in Order 693 associated with these standards. Review and modifications to the existing VAR standards will also consider the Transmission Issues Subcommittee’s “Reactive Support & Control Whitepaper” dated 05/18/2009.

Standards affected: VAR-001, VAR-002

**IN DEVELOPMENT
PROJECTS TEAM**

Project 2008-02 Undervoltage Load Shedding

Summary:

This project will improve the existing standards on Under Voltage Load Shedding (UVLS) to ensure that load is shed when needed to prevent voltage collapse and voltage instability in the bulk electric system. The existing standards will be consolidated and specific criteria for UVLS programs and assessments of those UVLS programs should be added. ‘Fill-in-the-blank’ elements should be eliminated, and concerns related to Fault-Induced Delayed Voltage Recovery will be reviewed and addressed.

Standards affected: PRC-010, PRC-022

**IN DEVELOPMENT
5-YEAR REVIEW TEAM**

Project 2008-12 Coordinate Interchange Standards

Summary:

This project will comprehensively review and revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator, or user of the bulk power system, and not to a tool used to coordinate interchange; to address the Interchange Subcommittee concerns related to the Dynamic Transfers and Pseudo-ties; to address a NAESB concern about inter-BA tagging, and to address other suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 submitted by stakeholders, other drafting teams, and FERC staff.

Standards affected: INT-001, INT-003, INT-004, INT-005, INT-006, INT-007, INT-008, INT-009, INT-010

**IN DEVELOPMENT
5-YEAR REVIEW TEAM**

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

Summary:

This project will create new or revised standards to establish requirements for the monitoring and analysis capabilities provided to System Operators to support Real-time System Operations. The project will address availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management.

Standards affected: New

**IN DEVELOPMENT
5-YEAR REVIEW TEAM**

Project 2009-03 Emergency Operations

Summary:

This project will comprehensively review and revise the set of EOP standards to ensure the requirements are clear and unambiguous. Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process and the standards are due for a comprehensive review. Suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 have been submitted by stakeholders, other drafting teams, and FERC staff.

Standards affected: EOP-001, EOP-002, EOP-003, EOP-004, EOP-005, EOP-006, EOP-008, EOP-009, IRO-001

**IN DEVELOPMENT
RESEARCH REQUESTED
PROJECTS TEAM**

Project 2009-04 Phasor Measurements

Summary:

This project will review several industry studies to determine if there should be phasor requirements developed for a NERC standard. This project is related to the North American Synchro-Phasor Initiative, and supports a blackout recommendation.

Standards affected: New

Requested Deliverable from the Operating Committee:

The Operating Committee has been asked to provide an analysis of the industry studies that have been performed to determine if there should be phasor requirements developed for a NERC standard.

CANDIDATE FOR DISMISSAL

Project 2009-05 Resource Adequacy Assessments

Summary:

This project will implement certain recommendations related to resource adequacy from the *Resource and Transmission Adequacy Task Force (RTATF) Report* and the *Gas/Electricity Interdependency Task Force Report*, approved by the NERC Board on June 15, 2004. The project will create a standard with requirements to perform resource adequacy assessments, using metrics that take into account various factors (including, but not limited to, fuel deliverability). The standard would also make the results of the assessments available to the industry, NERC, and appropriate regulatory agencies.

Standards affected: New

Status: This project will be reviewed to determine if changes to existing standards since the creation of the SAR have made this project obsolete.

**IN DEVELOPMENT
RESEARCH REQUESTED
PROJECTS TEAM**

Project 2009-07 Reliability of Protection Systems

Summary:

This project will ensure Protection Systems are designed and installed with redundancy where appropriate, such that if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards.

Standards affected: New

Requested Deliverable from the Planning Committee:

The Planning Committee has been asked to provide a report providing the conditions under which Protection Systems must be designed and installed with redundancy, such that if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards, taking into account the data that is being collected by NERC under the FERC Order 754 Data Request project.

**IN DEVELOPMENT
RESEARCH REQUESTED
PROJECTS TEAM**

Project 2010-01 Support Personnel Training

Summary:

This project will develop a standard that requires the use of a systematic approach to determining training needs of generator operators and operations planning and support staff with a direct impact on the reliable operations of the bulk power system.

Standards affected: New

Requested Deliverable from the Operating Committee:

The Operating Committee has been asked to provide an analysis of whether the following recommendation from the August 14, 2003 Blackout Report are still valid. If so, determine whether the development of a NERC standard is necessary to meet the recommendations.

NERC should require training for the planning staff at control areas and reliability coordinators concerning power system characteristics and load, VAR, and voltage limits, to enable them to develop rules for operating staff to follow.

NERC should require control areas and reliability coordinators to train grid operators, IT support personnel, and their supervisors to recognize and respond to abnormal automation system activity.

**IN DEVELOPMENT
RESEARCH REQUESTED
5-YEAR REVIEW TEAM**

Project 2010-02 Connecting New Facilities to the Grid

Summary:

This project will ensure that all of the elements that should be addressed when a new facility is connected to the grid are included in the revised standards. In addition, a comprehensive review of FAC-001 and -002 will be done to address suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 submitted by stakeholders, other drafting teams, and FERC staff.

Standards affected: FAC-001, FAC-002

Requested Deliverable from the Planning Committee:

The Planning Committee has been asked to provide the elements that should be addressed in revised FAC-001 and/or FAC-002 when a new facility is connected to the grid.

**IN DEVELOPMENT
RESEARCH REQUESTED
DIRECTIVES TEAM**

Project 2010-03 Modeling Data

Summary:

This project will consider merging, upgrading and expanding existing requirements for entities to provide data used to model the bulk electric system. This project is related the Modeling Initiative, and supports a blackout recommendation.

Standards affected: MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, PRC-013, PRC-015

Requested Deliverable from the Planning Committee:

The Planning Committee has been asked to provide a technical report providing an analysis of merging, upgrading and expanding existing requirements for entities to provide data used to model the bulk electric system. The technical report should revisit the industry practices on modeling in light of the Southwest blackout and design a framework for modeling.

**IN DEVELOPMENT
RESEARCH REQUESTED
DIRECTIVES TEAM**

Project 2010-04 Demand Data

Summary:

This project will consolidate MOD-016 through MOD-020 into a single standard, with MOD-021 remaining as a separate standard. Requirements will be made be more specific to clearly identify the format for providing data, and modifications will made in support if previously received industry comments and regulatory directives.

Standards affected: MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, MOD-021

Requested Deliverable from the Planning Committee:

The Planning Committee has been asked to provide an analysis of which requirements should be modified to be more specific and clearly identify the format for providing demand data. The technical report should provide a design for the consolidation of the MOD standards, taking into consideration the EIA data collection efforts.

**IN DEVELOPMENT
PROJECTS TEAM**

Project 2010-05.1 Phase 1 of Protection Systems: Misoperations

Summary:

This project addresses a key element for Bulk Electric System (BES) reliability: the correct performance of Protection Systems. Monitoring BES Protection System events to identify and correct the root causes of Misoperations will improve overall Protection System performance. The project will revise the definition of Misoperation and redraft the standard to be more clear and unambiguous.

Standards affected: PRC-003, PRC-004

**IN DEVELOPMENT
RESEARCH REQUESTED
PROJECTS TEAM**

Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS

Summary:

This project will modify the current standards and definitions related to SPS/RAS Misoperations to support a good metric for measurement of Protection System performance and to ensure the reliability of the bulk power system. This project is related to the System Protection Initiative.

Standards affected: PRC-012, PRC-014, PRC-016.

Requested Deliverable from the Planning Committee:

The Planning Committee has been asked to provide an analysis of what would constitute a good metric or metrics for the measurement of Protection System performance as related to SPS/RAS misoperations.

**IN DEVELOPMENT
PROJECTS TEAM**

Project 2010-08 Functional Glossary Model Revisions

Summary:

This project will ensure the definitions of various functional entities between the Functional Model, the NERC Glossary of Terms, and the NERC Statement of Compliance Registration Criteria is consistent.

Standards affected: NERC *Glossary of Terms*

**IN DEVELOPMENT
5-YEAR REVIEW TEAM**

Project 2010-11 TPL Table 1, Footnote B

Summary:

This project addresses the requirement in FERC Order RM06-16-009 to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system by June 30, 2010.

Standards affected: TPL-001, TPL-002, TPL-003, and TPL-004

**IN DEVELOPMENT
PROJECTS TEAM**

Project 2010-13.2 Phase 2 of Relay Loadability: Generation

Summary:

This project is being created in response to directives included in FERC Order 733. The project will draft a new standard to address generator relay loadability.

Standards affected: PRC-025

**IN DEVELOPMENT
RESEARCH REQUESTED
PROJECTS TEAM**

Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings

Summary:

This project is being created in response to directives includes in FERC Order 733. The project will draft a new standard to address protective relay operations due to power swings.

Standards affected: New

Requested Deliverable from the Planning Committee:

The Planning Committee has been asked to provide specifications of what is necessary to address protective relay operations due to power swings.

**IN DEVELOPMENT
PROJECTS TEAM**

**Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls:
Reserves**

Summary:

This project will review the standard related to Control Performance and Disturbance control, and propose modifications or new standards as necessary. This project includes the testing and analysis of the new Balancing Authority ACE Limit (BAAL) metric, as well as the development of a continent-wide reserve policy to support BAL-01, BAL-002, and BAL-003.

Standards affected: BAL-001, BAL-002, BAL-012, BAL-013

CANDIDATE FOR DISMISSAL

Project 2010-14.2 Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error, AGC, and Inadvertent

Summary:

This project will consider the Time Error Correction standard, AGC, standard, and Inadvertent Accounting standard to determine what changes, if any, are necessary to ensure the standards are clear and unambiguous. In some cases, the standard may no longer be necessary.

Standards affected: BAL-004, BAL-005, BAL-006

Status: This project will be reviewed to determine if changes to existing standards since the creation of the SAR have made this project obsolete.

**IN DEVELOPMENT
PROJECTS TEAM**

Project 2010-16 Definition of System Operator

Summary:

This project will remove the 'Generator Operator' from the current definition of System Operator. This will more accurately establish the responsibilities and expectations of the Generator Operator consistent with the current manner in which the Bulk Electric System is operated.

Standards affected: TBD

**IN DEVELOPMENT
5-YEAR REVIEW TEAM**

Project 2010-17 Definition of Bulk Electric System

Summary:

This project will revise the definition of Bulk Electric System (BES) to address various Federal Energy Regulatory Commissions (FERC) concerns the definition must be modified to encompass all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. These concerns have been identified in FERC Order 693 issued on March 16, 2007 and in Order 743 issued on November 18, 2010 (Order 743). The project will also consider additional modifications (beyond those established in the regulatory directives) to improve clarity, to reduce ambiguity and to establish consistency across all Regions in distinguishing between BES and non-BES Elements and Facilities.

Standards affected: Definition of *Bulk Electric System*

**IN DEVELOPMENT
RESEARCH REQUESTED
PROJECTS TEAM**

Project 2012-01 Equipment Monitoring and Diagnostic Devices

Summary:

This project will consider the development of reliability standards for the application of major equipment monitoring and diagnostic devices and procedures, with the intent of identifying potential equipment failures prior to their occurrence. This will provide more time to address failing systems and avoid or minimize long lead times.

Standards affected: New

Requested Deliverable from the Operating Committee:

The Operating Committee has been asked to provide an analysis of the major equipment monitoring and diagnostic devices and procedures necessary to identify potential equipment failures prior to their occurrence.

CANDIDATE FOR DISMISSAL

Project 2012-02 Physical Protection

Summary:

This project will develop standards for the safety and protection of essential equipment, buildings, and people located in power generation, transmission, or distribution system locations in order to mitigate the associated reliability risks to the bulk power system.

Standards affected: New

Status: This project will be submitted to the RISC to be reviewed to determine if a NERC standard is necessary to address the perceived need.

CANDIDATE FOR DISMISSAL

Project 2012-03 PRC-004 VSLs

Summary:

This project will address a problem identified in the VSLs of PRC-004. Currently, the VSLs do not address the case where a Corrective Action Plan was developed or documented, but not fully implemented.

Standards affected: PRC-004

Status: This project will be incorporated into the existing Project 2010-05.1, which is revising PRC-004.

**IN DEVELOPMENT
RESEARCH REQUESTED
PROJECTS TEAM**

Project 2012-04 Protection System Commissioning Testing

Summary:

This project will address a gap in reliability related to protection systems by creating a standard that requires commissioning testing. Improper or inadequate commissioning testing practices are a common cause of protection system Misoperation. However, the current set of approved NERC reliability standards does not address the testing of protection system equipment *before* that equipment is placed into initial service. Creating a commissioning standard would also enhance the effectiveness of the mandatory auditing program.

Standards affected: New

Requested Deliverable from the Planning Committee:

The Planning Committee has been asked to provide specifications of what is necessary for protection systems commissioning testing.

**IN DEVELOPMENT
DIRECTIVES TEAM**

Project 2012-05 ATC Revisions - Order 729

Summary:

This project will respond to the remaining directives in Order 729.

Standards affected: MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, MOD-030

Status: This is a new project, which will require SAR development. It is estimated this project will start in Q3 2014 and complete in Q1 2016.

**IN DEVELOPMENT
RESEARCH REQUESTED
PROJECTS TEAM**

Project 2012-06 Generator Capabilities

Summary: This project will develop standards to ensure generator performance. The project should consider requirements that specify governor droop, frequency response, and reactive response.

Standards affected: New

Requested Deliverable from the Planning Committee:

The Planning Committee has been asked to provide specifications of what is necessary for governor droop, frequency response for individual units, and reactive response.

CANDIDATE FOR DISMISSAL

Project 2012-07 Obsolescence Review

Summary:

This project will create a standard that requires Generator and Transmission Owners periodically review their control and protection systems to identify and electronic, electrical, or mechanical devices that have become obsolete.

Standards affected: New

Status: This project will be submitted to the RISC to be reviewed to determine if a NERC standard is necessary to address the perceived need.

**IN DEVELOPMENT
DIRECTIVES TEAM**

Project 2012-08 Glossary Updates

Summary: This project will respond to FERC directives to either create or modify the following definitions: Transmission Operator, Generator Operator, Bulk Power System, Reliable Operation, and Reliability Standard.

Standards affected: TBD

**IN DEVELOPMENT
5-YEAR REVIEW TEAM**

Project 2012-09 IRO Review

Summary: This project will perform the five-year review of several IRO standards, pursuant to NERC's Rules of Procedure.

Standards affected: IRO-006, IRO-006-EAST, IRO-008, IRO-009, and IRO-010

**IN DEVELOPMENT
5-YEAR REVIEW TEAM**

Project 2012-11 FAC Review

Summary: This project will perform the five-year review of several FAC standards, pursuant to NERC's Rules of Procedure.

Standards affected: FAC-010, FAC-011, FAC-014

**IN DEVELOPMENT
DIRECTIVES TEAM**

Project 2012-12 PER Review

Summary: This project will perform the five-year review of several PER standards, pursuant to NERC's Rules of Procedure.

Standards affected: PER-003, PER-004,

**IN DEVELOPMENT
5-YEAR REVIEW TEAM**

Project 2012-13 NUC Review

Summary: This project will perform the five-year review of the NUC standard, pursuant to NERC's Rules of Procedure.

Standards affected: NUC-001

CANDIDATE FOR DISMISSAL

Project 2012-14 Risk Analysis

Summary: This project will develop a standard that requires entities to have and maintain a checklist of potential threats to the power system that must be addressed by each TOP/BA. The checklist would include things like GMD, voltage collapse, and other extreme events.

Standards affected: New

Status: This project will be submitted to the RISC to be reviewed to determine if a NERC standard is necessary to address the perceived need.

**IN DEVELOPMENT
PROJECTS TEAM**

Project 2012-15 Flow Limited Paths

Summary: The MOD-029 standard includes a provision that, if left uncorrected, could in certain scenarios result in significantly over-conservative ATC values being calculated. This project will address this problem.

Standards affected: MOD-029

**IN DEVELOPMENT
PROJECTS TEAM**

Project 2013-01 Cold Weather Preparedness

Summary: To require GO/GOPs to report generating unit capabilities based on anticipated winter weather using criteria developed by the standard drafting team using stakeholder input. GO/GOPs must ensure winter weather preparation plans are created, maintained, implemented and monitored as appropriate to help ensure generating units can operate to the criteria developed above. The plans shall include appropriate annual winterization measures.

Standards affected: TBD

**IN DEVELOPMENT
5-YEAR REVIEW TEAM**

Project 2013-02 Paragraph 81

Summary: The purpose of the project is to retire or modify FERC-approved Reliability Standard requirements that as FERC noted in its March 15, 2012 Order, "provide little protection to the reliable operations of the BES", are redundant or unnecessary, or to retire or modify a FERC-approved Reliability Standard requirement to increase the efficiency of the ERO's compliance programs.

Standards affected: TBD

**CANDIDATE FOR 2013
5-YEAR REVIEW TEAM**

Project 2013-03 Geomagnetic Disturbance Mitigation

Summary: If FERC directs a standard or standards to be developed, a project will be initiated.

Standards affected: TBD

January 4, 2013

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

**Re: Errata to Petition of the North American Electric Reliability Corporation for Approval of
Proposed Reliability Standard EOP-004-2 – Event Reporting
Docket No. RD13-3-000**

Dear Ms. Bose:

On December 31, 2012, NERC filed a Petition for Approval of Proposed Reliability Standard EOP-004-2 – Event Reporting. It has come to NERC's attention that Exhibit B -- *Proposed Reliability Standard EOP-004-2 Submitted for Approval*, contains a minor error. A corrected copy of this Exhibit is attached.

Accordingly, NERC respectfully requests that the Commission take note of this errata filing, and issue an order consistent with NERC's filings submitted in this proceeding.

Respectfully submitted,

/s/ Stacey Tyrewala

Stacey Tyrewala

Attorney for North American Electric Reliability
Corporation

cc: Official service list in Docket Nos. RD13-3-000

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

A. Introduction

- 1. Title:** Event Reporting
- 2. Number:** EOP-004-2
- 3. Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
- 4. Applicability:**
 - 4.1.** Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
 - 4.1.1.** Reliability Coordinator
 - 4.1.2.** Balancing Authority
 - 4.1.3.** Transmission Owner
 - 4.1.4.** Transmission Operator
 - 4.1.5.** Generator Owner
 - 4.1.6.** Generator Operator
 - 4.1.7.** Distribution Provider

5. Effective Dates:

The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
3. Specific references to the DOE form need to be eliminated.
4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

B. Requirements and Measures

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2 Attachment 1 and in accordance with the entity responsible for reporting.
- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2 Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the

end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium]*
[Time Horizon: Operations Planning]
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

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

1.2 Evidence Retention

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

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

1.3 Compliance Monitoring and Enforcement 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	Operations Planning	Lower	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment	Medium	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours. OR The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	Medium	The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month. OR The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.	The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months. OR The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.	The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months. OR The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.	The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more. OR The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.

D. Variances

None.

E. Interpretations

None.

F. References

Guideline and Technical Basis (attached)

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.
Damage or destruction of a Facility	BA, TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action.
Physical threats to a Facility	BA, TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.

EOP-004-2 — Event Reporting

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Physical threats to a BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a BES control center.
BES Emergency requiring public appeal for load reduction	Initiating entity is responsible for reporting	Public appeal for load reduction event.
BES Emergency requiring system-wide voltage reduction	Initiating entity is responsible for reporting	System wide voltage reduction of 3% or more.
BES Emergency requiring manual firm load shedding	Initiating entity is responsible for reporting	Manual firm load shedding ≥ 100 MW.
BES Emergency resulting in automatic firm load shedding	DP, TOP	Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or SPS/RAS).
Voltage deviation on a Facility	TOP	Observed within its area a voltage deviation of $\pm 10\%$ of nominal voltage sustained for ≥ 15 continuous minutes.

EOP-004-2 — Event Reporting

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)	RC	Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).
Loss of firm load	BA, TOP, DP	Loss of firm load for ≥ 15 Minutes: ≥ 300 MW for entities with previous year's demand $\geq 3,000$ OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA, GOP	Total generation loss, within one minute, of : $\geq 2,000$ MW for entities in the Eastern or Western Interconnection OR $\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement

EOP-004-2 — Event Reporting

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of voice communication capability	RC, BA, TOP	Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.
Complete loss of monitoring capability	RC, BA, TOP	Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form		
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780.		
Task	Comments	
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No ☐ Unknown ☐
4.	Event Identification and Description: (Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical Threat to a Facility ☐ Physical Threat to a control center ☐ BES Emergency: ☐ public appeal for load reduction ☐ system-wide voltage reduction ☐ manual firm load shedding ☐ automatic firm load shedding ☐ Voltage deviation on a Facility ☐ IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) ☐ Loss of firm load ☐ System separation ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ unplanned control center evacuation ☐ Complete loss of voice communication capability ☐ Complete loss of monitoring capability	
	Written description (optional):	

Guideline and Technical Basis

Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to

reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

Data Gathering

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

Law Enforcement Reporting

The reliability objective of EOP-004-2 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Present expectations of the industry under CIP-001-1a:

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

Coordination of Local and State Law Enforcement Agencies with the FBI

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

Coordination of Local and Provincial Law Enforcement Agencies with the RCMP

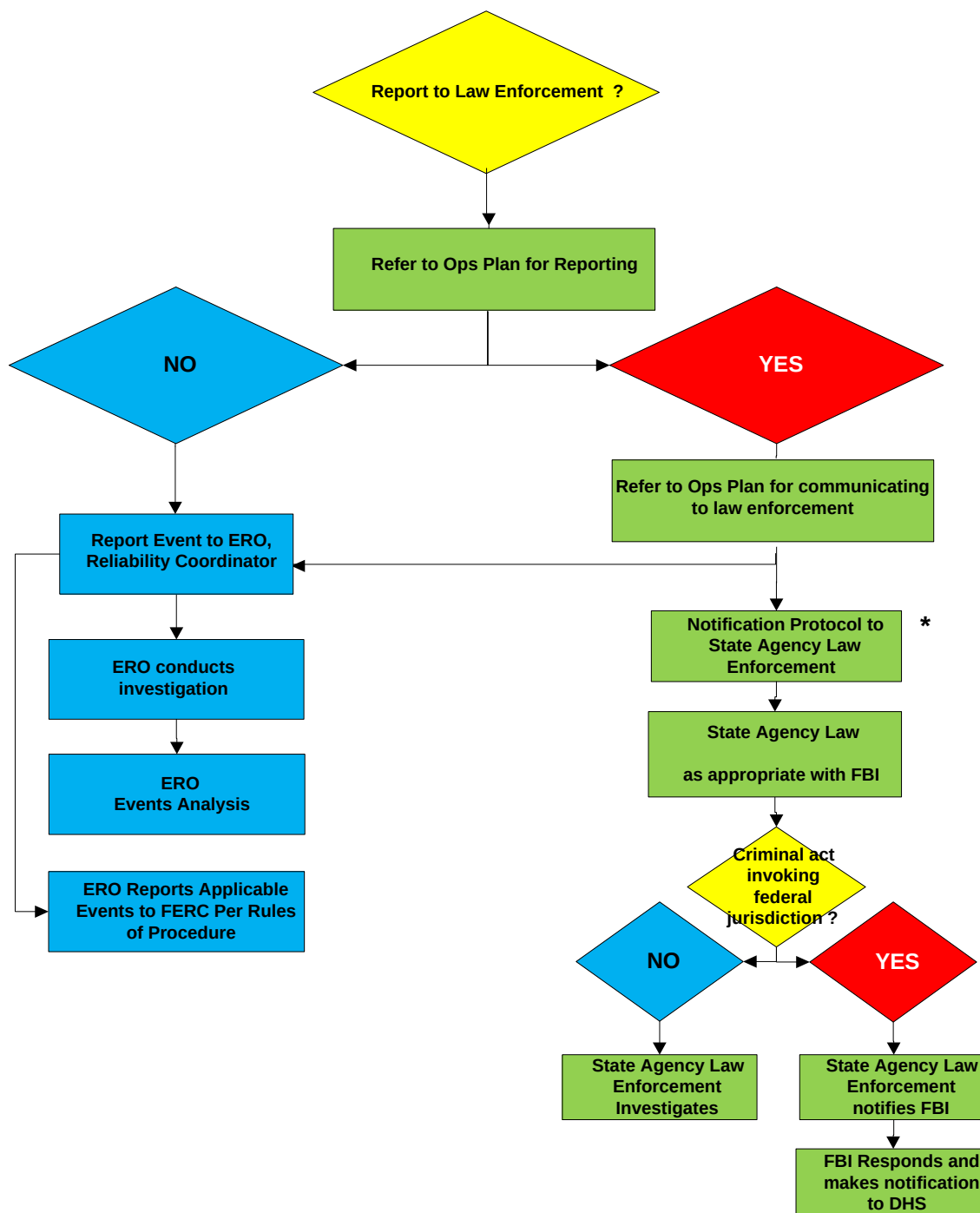
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

A Reporting Process Solution – EOP-004

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

Summary of Concepts and Assumptions:

The Standard:

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

Discussion of Disturbance Reporting

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

Discussion of Event Reporting

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

What about sabotage?

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *" . . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

Potential Uses of Reportable Information

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Collection of Reportable Information or “One stop shopping”

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

Rationale:

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

Rationale for R1:

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

Rationale for R2:

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

Rationale for R3:

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

Rationale for EOP-004 Attachment 1:

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined 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.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**COORDINATION BETWEEN NATURAL)
GAS AND ELECTRICITY MARKETS)**

Docket No. AD12-12-000

**COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION**

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability
Corporation
3353 Peachtree Road N.E.
Suite 600, North Tower
Atlanta, GA 30326-1001
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net

January 7, 2013

I. INTRODUCTION

The North American Electric Reliability Corporation (“NERC”) is pleased to provide these comments in response to the Federal Energy Regulatory Commission’s (“FERC” or the “Commission”) Notice of Request for Comments and Technical Conference on the Coordination between Natural Gas and Electricity Markets (“Notice”).¹

NERC’s mission, as the FERC-designated Electric Reliability Organization (“ERO”),² is to ensure the reliability of the Bulk Power System in North America, in part, by developing and enforcing mandatory Reliability Standards. NERC’s reliability mandate under Section 215 of the Federal Power Act (“FPA”)³ does not include authority to monitor and enforce market-based issues.⁴ Accordingly, NERC’s comments herein focus on electric and gas industry coordination issues as they relate to electric reliability.

By this filing, NERC provides comments in response to the Commission’s Notice.

¹ *Notice of Request for Comments and Technical Conference, Coordination between Natural Gas and Electricity Markets*, Docket No. AD12-12-000 (December 7, 2012).

² *See North American Electric Reliability Corporation, Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006).

³ 16 U.S.C. § 824o.

⁴ *See Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power System*, Order No. 729, 129 FERC ¶ 61,155 at P 109 (2009).

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:⁵

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability
Corporation
3353 Peachtree Road N.E.
Suite 600, North Tower
Atlanta, GA 30326-1001
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco*
Senior Vice President and General Counsel
Holly A. Hawkins*
Assistant General Counsel
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net

III. COMMENTS

FERC's Notice provides that a technical conference will be held on February 13, 2013 at the FERC offices in Washington, DC. In advance of the technical conference, interested parties were asked to submit comments on specific questions included in the Notice related to communications and information sharing. NERC is providing comments related to the issue of coordination between natural gas and electricity markets generally to help provide additional support to the Commission in its planning of the technical conference. Given NERC's responsibility to assess the reliability of the bulk power system, NERC has identified high-level communication and coordination considerations for all entities (directly or indirectly) involved in generating, transmitting, and balancing electricity.

⁵ Persons to be included on FERC's service list are indicated with an asterisk.

In formulating comments, NERC refers to its December 2011 Special Reliability Assessment titled “A Primer of the Natural Gas and Electric Power Interdependency in the United States.”⁶ Phase I recommendations from this assessment include:

- Future natural gas storage facilities will not only have to satisfy the traditional demands for fuel supply reliability, but it will also have to satisfy the significant and expanding swings in demand for gas that can only be accommodated by high performance, multiple cycle natural gas storage facilities.
- Vital information needed for the reliable operation of the Bulk Power System should be shared with system operators from both industries—increased transparency in both markets is needed. Examples of this include the sharing of maintenance issues (*e.g.*, the pipeline and the generators), new facilities perceived impact, load levels, dispatch principles and general patterns or forecasts for both industries.
- Communications between two industries are hampered by the incompatibility between the traditional gas day, traditional electric day, and the market day (in market areas), which increases the difficulty of the gas industry providing the needed services to its largest consumers. Contracting practices also make it difficult to plan the flexibility needed for both industries’ reliable operation. A coordinated approach for engaging the two industries to come together and develop compromising solutions to address communication strategies, operational changes, and tariff changes is critical. The two industries must reconcile the divergent views such as firm contracting needed to build new pipeline capacity and how to secure day-to-day delivery of gas.

⁶See *NERC 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States*, at p. 96 (December 2011), available at: http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf.

- Vulnerabilities should be identified. Mitigating strategies should be incorporated into the planning and operation procedures for both industries. The electric industry should evaluate which generators may be most susceptible to pipeline disruptions (*e.g.*, number of pipelines serving the generator, proximity to gas storage, and location relative to pipeline). The gas pipeline industry should consider electric system generation forecasts during the planning process. For operations, the sharing of real-time system information by both industries increases the ability for each to make informed decisions and reduce overall risk.

NERC also references its on-going Phase II⁷ activities which are highlighted in the *2012 Long-Term Reliability Assessment*⁸ and also cited in the FERC Staff Report on Gas-Electric Coordination Technical Conferences (“FERC Staff Report”).⁹ A key element of focus in NERC’s Phase II activities is the interface between the electric power and natural gas industries and the need for increased coordination between the two industries, particularly at the regional level. While addressing interdependency issues requires a coordinated approach to ensure reliability of the electric and gas systems, Phase II activities focus solely on the electric industry’s dependence on gas, and therefore identify issues and recommendations to ensure bulk power system reliability.

Two high-level objectives expected as a result of NERC’s assessment are:

⁷ NERC presented a status report at the September 2012 Planning Committee Meeting on Phase II activities: <http://www.nerc.com/docs/pc/Planning%20Committee%20Presentations%20-%20September%2018-19,%202012%20%28St.%20Louis,%20MO%29.pdf> (pg123-139)

⁸ NERC 2012 Long-Term Reliability Assessment: http://www.nerc.com/files/2012_LTRA_FINAL.pdf

⁹ *FERC Staff Report on Gas-Electric Coordination Technical Conferences (Docket No. AD12-12-000)*: <http://www.ferc.gov/legal/staff-reports/11-15-12-coordination.pdf>

1. NERC must ensure that enhancements to planning processes are made to account for any expected uncertainty in gas-fired generation performance as well as potential contingencies on the pipeline network.
2. Operational procedures must include a certain level of formalized coordination and communication with the gas pipeline industry, with specific focus on emergency procedures during extreme events.

While NERC believes that improved sharing of information and improved scheduling of existing pipeline capacity will help both the electric and gas industries harmonize their practices, NERC's primary focus is assessing resource adequacy and ensuring thorough technical analysis and sound assumptions are applied. With respect to coordinated long-term planning, an enhanced framework may be needed for infrastructure development to support a planning approach that takes into account future needs of pipeline customers.

NERC agrees with the FERC Staff Report that resource adequacy issues in wholesale market areas should continue to be addressed in the first instance by market participants, states, and other stakeholders in each area. In light of the unique characteristics of each region, which significantly impacts the dependencies between the two industries, there are significant regulatory, market, and physical differences that are best resolved at a more granular level. Also, each region may develop different approaches for interacting with critical third-parties (*e.g.*, regulatory bodies) on endorsing new procedures and approaches in order to preclude the loss of system reliability during periods of extreme stress. These new procedures and approaches, depending upon the region, might include provisions for procuring pipeline capacity and greater discretion on emission requirements during emergency conditions (*e.g.*, the use of fuel switching to preclude rolling blackouts), among other things.

NERC also notes that a common characteristic of long- and short-term planning, operational planning, and real-time operations is communication. The sharing of vital information needed for the reliable operation of the bulk power system between both gas and electric industries should be a top priority.

Of specific interest in communication and coordination are the information needs of Balancing Authorities, Reliability Coordinators, and Planning Coordinators. In general, it is important for Balancing Authorities and Reliability Coordinators to have information on pipeline availability, scheduled and unscheduled outages, the amount of gas that is available, and the commitments within the operational planning time horizon (*e.g.*, 6 months to 1 day). This level of observability would allow system operators to predict a potential inadequacy of fuel supplies and consider alternative measures (*e.g.*, dispatching dual-fuel capable generation, storage solutions, or liquefied natural gas deliveries).

From a coordinated planning perspective, Planning Coordinators should understand and consider fuel-supply risks in general and not limit to natural gas to support the short-term to long-term planning time horizon (*e.g.*, 1 to 10 years). In order to ascertain the risks of fuel interruption, information on contractual rights to firm pipeline capacity must be shared with Balancing Authorities, Reliability Coordinators, and Planning Coordinators. For planning purposes, this information is vital for resource adequacy analysis and can supplement existing forced outage rate calculations related to loss of fuel.

Formalized communication procedures and expectations may also be needed between bulk power system operating and planning entities (*i.e.*, Balancing Authorities, Reliability Coordinators, and Planning Coordinators) and Generator Owners and Generator Operators. Where operating and planning functions are disconnected from asset ownership (*i.e.*, wholesale

market areas), Generator Owners and Operators should keep planning and operating entities well-informed of both fuel expectations and dual-fuel capabilities. Specifically, sharing of information on fuel schedules and scheduled fuel supply would help inform system operators in advance of any potential interruption issues.

IV. CONCLUSION

NERC looks forward to continued participation in FERC's February 13, 2013 technical conference and supports increased communication and information sharing between the natural gas and electricity markets in the United States.

Respectfully submitted,

/s/ Holly A. Hawkins

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability
Corporation
3353 Peachtree Road N.E.
Suite 600, North Tower
Atlanta, GA 30326-1001
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 7th day of January, 2013.

/s/ Holly A. Hawkins

Holly A. Hawkins

*Assistant General Counsel for North
American Electric Reliability Corporation*

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**Reliability Standards for
Geomagnetic Disturbances**

)
)

Docket Nos. RM12-22-000

**REPLY 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 comments submitted on the Federal Energy Regulatory Commission’s (“FERC” or the “Commission”) October 18, 2012, Notice of Proposed Rulemaking (“NOPR”)² proposing to direct NERC to file for approval with the Commission Reliability Standards that address the risks posed by geomagnetic disturbances (“GMDs”) to the reliable operation of the Bulk-Power System, in two stages.

I. COMMENTS

In response to certain remarks, NERC offers clarifying comments on the NERC standard development process and the role of the geomagnetic disturbance task force (“GMD Task Force”).

A. Standard Development Process

The NERC standard development process is accredited by the American National Standards Institute (“ANSI”) and provides reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing a proposed Reliability Standard, consistent with the attributes necessary for ANSI accreditation. The same attributes, as

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. *North American Electric Reliability Corporation*, 116 FERC ¶ 61,062 (2006).

² *Reliability Standards for Geomagnetic Disturbances*, 141 FERC ¶ 61,045 (2012)(“NOPR”).

well as transparency, consensus-building, and timeliness, are also required under Section 304 of the NERC Rules of Procedure. Participation is open to all persons who are directly and materially affected by the reliability of the North American Bulk-Power System and is not conditioned upon membership in NERC or any other organization.³ In order to ensure this, all participants in the standards development process are expected to, and must, conduct themselves in a professional manner at all times and this includes in-person conduct and any communication, electronic or otherwise, made as a participant in the standards development process.⁴

The NERC standard development process builds and documents consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard, and the content. This process is transparent and provides reasonable notice and opportunity for any person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

B. Geomagnetic Disturbance Task Force

The formation of the GMD Task Force occurred following the publication of the High-Impact, Low Frequency Event Risk to the North American Bulk Power System Report (“HILF Report”).⁵ The NERC Electricity Sub-Sector Coordinating Council (“ESSC”)⁶ recommended that NERC, working with its stakeholders and appropriate government authorities, form a task

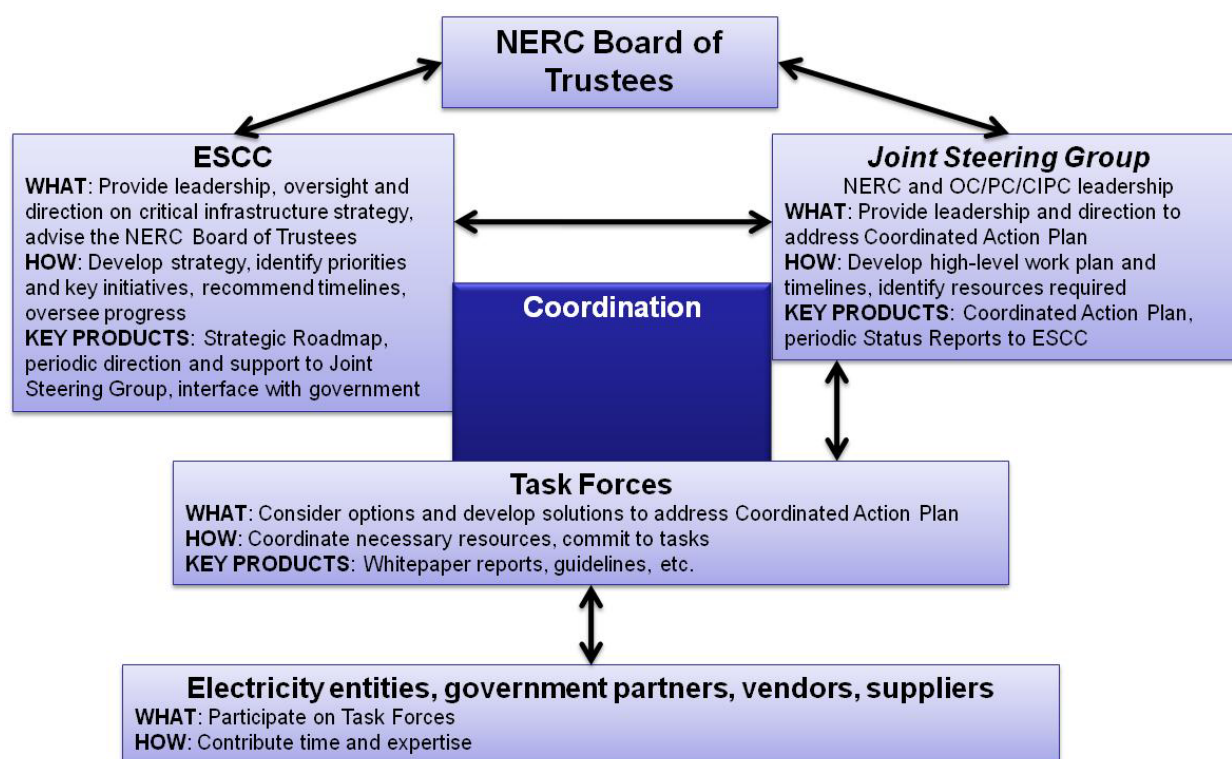
³ See Section 304 of the NERC Rules of Procedure.

⁴ See e.g., Standard Drafting Team Scope, available at: http://www.nerc.com/files/SDT_Scope_approved_by_SC_July_13_2011.pdf.

⁵ Available here: <http://www.nerc.com/files/HILF.pdf>.

⁶ The role of NERC’s Electricity Sub-Sector Coordinating Council is to “foster and facilitate the coordination of sector-wide policy-related activities and initiatives to improve the reliability and resilience of the electricity sector, including physical and cyber security infrastructure.” To help carry out that role, the ESSC developed a Critical Infrastructure Strategic Roadmap to recommend to NERC’s Board of Trustees that NERC’s Technical Committees and the industry place renewed emphasis on certain severe-impact risks to electricity system reliability.

force to identify and prioritize mitigation steps to protect the power system. The scope of the GMD Task Force was approved by the NERC Planning Committee at its September 14-25, 2010, meeting. It is a joint task force reporting to the Planning Committee (“PC”) and Operating Committee (“OC”) with support from the Critical Infrastructure Protection Committee (“CIPC”). A diagram is presented below for reference purposes.



To clarify the record, the meetings of the GMD Task Force are open and publicly-noticed. Pursuant to its certification as the Electric Reliability Organization (“ERO”) and Section 215 of the Federal Power Act, NERC is independent of the users and owners and operators of the Bulk-Power System, while assuring fair stakeholder representation and balanced decisionmaking.⁷

⁷ See Section 215(c)(2).

II. CONCLUSION

NERC supports the Commission's dedication to raising awareness in the industry of the possible impacts of GMD on the Bulk-Power System and is committed to working with stakeholders and the Commission to address these issues. For the reasons stated above, NERC respectfully requests that the Commission accept these reply comments for consideration.

Respectfully submitted,

/s/ Stacey Tyrewala

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability
Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Stacey Tyrewala
Attorney
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

*Counsel for North American Electric
Reliability Corporation*

Dated: January 10, 2012

141 FERC ¶ 61,045
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM12-22-000]

Reliability Standards for Geomagnetic Disturbances

(Issued October 18, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Under section 215 of the Federal Power Act, the Federal Energy Regulatory Commission (Commission) proposes to direct the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, to submit for approval Reliability Standards that address the impact of geomagnetic disturbances (GMD) on the reliable operation of the Bulk-Power System. The Commission proposes to do this in two stages. In the first stage, the Commission proposes to direct NERC to file, within 90 days of the effective date of a final rule in this proceeding, one or more Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System. In the second stage, the Commission proposes to direct NERC to file, within six months of the effective date of a final rule in this proceeding, one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going

assessments of the potential impact of GMDs on Bulk-Power System equipment and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs identified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit. This second stage would be implemented in phases, focusing first on the most critical Bulk-Power System assets.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through <http://www.ferc.gov>. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

David Huff (Technical Information)
Office of Electric Reliability
Division of Security
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(301) 665-1603
David.Huff@ferc.gov

Matthew Vlissides (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8408
Matthew.Vlissides@ferc.gov

SUPPLEMENTARY INFORMATION:

141 FERC ¶ 61,045
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Standards for Geomagnetic Disturbances

Docket No. RM12-22-000

NOTICE OF PROPOSED RULEMAKING

(Issued October 18, 2012)

1. Pursuant to section 215(d)(5) of the Federal Power Act (FPA),¹ the Federal Energy Regulatory Commission (Commission) proposes to direct the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), to file for approval with the Commission Reliability Standards (GMD Reliability Standards) that address the risks posed by geomagnetic disturbances (GMD) to the reliable operation of the Bulk-Power System.² The Commission proposes to direct NERC to develop the GMD Reliability Standards in two stages. In the first stage, within 90 days of the effective date of a final rule in this proceeding, NERC would file one or more proposed Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the

¹ 16 U.S.C. 824o(d)(5) (2006).

² “A geomagnetic disturbance occurs when the magnetic field embedded in the solar wind is opposite that of the earth. This disturbance, which results in distortions to the earth’s magnetic field, can be of varying intensity and has in the past impacted the operation of pipelines, communications systems, and electric power systems.” Oak Ridge National Laboratory, *Electric Utility Industry Experience with Geomagnetic Disturbances* at xiii (1991), available at <http://www.ornl.gov/~webworks/cpr/v823/rpt/51089.pdf>.

effects of GMDs consistent with the reliable operation of the Bulk-Power System. In the second stage, within six months of the effective date of a final rule in this proceeding, NERC would file one or more proposed Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of GMDs on Bulk-Power System equipment and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD.³ This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs identified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents (GICs) from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.⁴ This second stage would be implemented in phases, focusing first on the most critical Bulk-Power System assets.

³ 16 U.S.C. 824o(a)(4) (2006).

⁴ Some examples of automatic blocking include series line capacitors, transformer neutral GIC blocking and/or reduction devices, and selective tripping of vulnerable

(continued...)

2. We take this action based on government-sponsored studies and NERC studies that conclude that GMD events can have an adverse, wide-area impact on the reliable operation of the Bulk-Power System.⁵ In a 2010 study prepared for the Commission, Department of Energy, and Department of Homeland Security, the Oak Ridge National Laboratory reported that GMD events can develop quickly over large geographic footprints, having the capability to produce geographically-large outages and significant damage to Bulk-Power System equipment.⁶

3. The seriousness of the risk posed by GMDs to the reliable operation of the Bulk-Power System was expressed at a Technical Conference held on April 30, 2012.⁷ At the Technical Conference, several panelists indicated that severe GMD events could potentially compromise the reliable operation of the Bulk-Power System, with some

assets. Automatic blocking measures can also include the use of relays that can be set so that they are activated only when needed.

⁵ See, e.g., The Oak Ridge National Laboratory prepared a study consisting of six technical reports (collectively, “Oak Ridge Study”) on the effects of electromagnetic pulses on the Bulk-Power System. Available at http://www.ornl.gov/sci/ees/etsd/pes/ferc_emp_gic.shtml; North American Electric Reliability Corp., 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System at 85 (February 2012) (*NERC Interim GMD Report*), available at <http://www.nerc.com/files/2012GMD.pdf>; North American Electric Reliability Corp., *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System* at 68 (June 2010) (*HILF Report*), available at <http://www.nerc.com/files/HILF.pdf>.

⁶ Oak Ridge National Laboratory, *Electromagnetic Pulse: Effects on the U.S. Power Grid: Meta-R-319* at pages 1-30, 1-31, 4-1 (January 2010) (*Oak Ridge Study 319 Report*), available at http://www.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf.

⁷ Written statements presented at the Technical Conference, post-Technical Conference comments, and Technical Conference transcript are accessible through the Commission’s eLibrary document retrieval system in Docket No. AD12-13-000.

noting as an example the GMD-induced disruption of the Hydro-Québec grid in 1989.⁸

At the Technical Conference, panelists stated that the current 11-year solar activity cycle is expected to hit its maximum activity in 2013 and large solar events often occur within four years of such a cycle maximum.⁹ While strong GMDs are infrequent events, their potential impact on the reliable operation of the Bulk-Power System (e.g., widespread blackouts) requires Commission action under section 215(d)(5) of the FPA.¹⁰

⁸ See, e.g., Statement of Scott Pugh, U.S. Department of Homeland Security at 2 (citing 1989 Hydro-Québec blackout); Statement of Frank Koza, PJM Interconnection, L.L.C. at 1 (“The combination of half-cycle transformer saturation and increased reactive power consumption can lead to voltage collapse and blackouts if not properly managed.”); Statement of John Kappenman at 8 (“The bulk power system is the nation’s most important critical infrastructure and unlike other threats, a severe geomagnetic storms [sic] can impose a near simultaneous nationwide crippling threat to this vital infrastructure.”); Statement of Gerry Cauley, NERC at 1 (“Previous examples, such as the 1989 event in Hydro Québec demonstrate that severe solar storms represent a serious risk that can challenge the reliability of the bulk power system.”).

⁹ April 30, 2012 Technical Conference Tr. 84:14-19 (Pugh); 106:9-15, 169:1-19 (Murtagh).

¹⁰ 16 U.S.C. 824o(d)(5); see also *Transmission Relay Loadability Reliability Standard*, 134 FERC ¶ 61,127, at P 25 (2011) (explaining that under section 215(d)(5) “the Commission, and not just the ERO, has the responsibility and authority to identify ‘specific matters’ that it considers appropriate to carry out section 215. Section 215 establishes a paradigm by which both the Commission and the ERO are responsible for identifying reliability gaps—the ERO through its Reliability Standards development process, where it can independently identify areas of concern and develop Standards to address them; and the Commission through its review of proposed Reliability Standards and authority to direct modifications or new Standards that address specific issues necessary to effectuate the purposes of section 215.”).

4. Currently, GMD vulnerabilities are not adequately addressed in the Reliability Standards.¹¹ This constitutes a reliability gap because, as discussed below, GMD events can cause the Bulk-Power System to collapse suddenly and can potentially damage the Bulk-Power System.

5. GMD events affect the Bulk-Power System by introducing geomagnetically-induced currents¹² that can cause “half-cycle saturation” of certain high-voltage Bulk-Power System transformers.¹³ Half-cycle saturation of transformers can lead to increased consumption of reactive power and creation of disruptive harmonics that can cause the sudden collapse of the Bulk-Power System.¹⁴ Further, half-cycle saturation from GICs can potentially damage Bulk-Power System transformers because of overheating.¹⁵

¹¹ NERC Reliability Standard IRO-005-3a (Reliability Coordination — Current Day Operations), Requirement R3, is the only existing requirement that discusses GMDs. Requirement R3 requires reliability coordinators to make transmission operators and balancing authorities aware of GMD forecast information and assist as needed in the development of response plans, but it does not require steps for mitigating the effects of GMD events.

¹² GIC is an electrical current created by a solar event that appears as direct current to the bulk electric system. North American Electric Reliability Council, *March 13, 1989 Geomagnetic Disturbance* at 36 (1989), available at <http://www.nerc.com/files/1989-Quebec-Disturbance.pdf>. Automatic blocking prevents or reduces GICs flows into protected Bulk-Power System components without operator intervention. *NERC Interim GMD Report* at 73.

¹³ NERC Interim GMD Report at iii-iv. Half-cycle saturation is an abnormal operating condition whereby a transformer operates outside nominal voltage design values, saturating the transformer core with magnetic flux and forcing magnetic flux into other parts of the transformer. *Id.* at 25.

¹⁴ *Id.* at 3 (“GMD can have ... a wide range of impacts on power apparatus and power system operations. The effects on apparatus range from nuisance events, such as tripping of electrical equipment, radio interference, and control malfunctions, to large-

(continued...)

Permanent damage to large transformers due to GICs can lead to restoration delays for the power grid.¹⁶ For example, the Oak Ridge Study assessed the effects of a “1-in-100 year” geomagnetic storm on the modern Bulk-Power System.¹⁷ The Oak Ridge Study simulation concluded that such an event could put a significant number of Bulk-Power System transformers at risk for failure or permanent damage.¹⁸ The Oak Ridge Study simulation also found that the effects of a GMD event may be substantially larger if it

scale events, such as voltage and reactive power fluctuations, local disruption of service, limited equipment failure, and potential voltage instability resulting in uncontrolled cascading of the bulk power system.”).

¹⁵ While disagreements exist as to the likely severity of transformer damage from GMDs compared with the likelihood of voltage collapse due to increased reactive power absorption arising from GMDs, there appears to be a consensus that GMDs can cause at least some damage to Bulk-Power System transformers. *See, e.g.*, Comments of the North American Electric Reliability Corporation, Docket No. AD12-13-000, at 5 (filed May 21, 2012) (“Though the most likely result is voltage collapse, the GMD Task Force members agreed that, depending on the transformer health, design, geology and geomagnetic latitude, geomagnetic induced current flows can result in transformer loss-of-life, and may ultimately result in the failure of some transformers.”).

¹⁶ *Oak Ridge Study 319 Report* at pages 4-1, 4-3 (“The recovery could plausibly extend into months in many parts of the impacted regions ... These multi-ton apparatus [transformers] generally cannot be repaired in the field, and if damaged in this manner, they need to be replaced with new units, which have manufacture lead times of 12 months or more in the world market.”); NERC Interim GMD Report at iv (“[R]estoration times for system collapse due to voltage instability would be a matter of hours to days, while replacing transformers requires long-lead times (a number of months) to replace or move spares into place, unless they are in a nearby location. Therefore, the failure of a large numbers [sic] of transformers would have considerable impacts on portions of the system.”).

¹⁷ *Oak Ridge Study 319 Report* at page 3-22.

¹⁸ *Id.* at page 1-14, Tables 4-1, 4-2, 4-3 (listing numbers of at-risk transformer).

occurred at lower latitudes.¹⁹ Estimates prepared by the National Research Council of the National Academies concluded that these events have the potential to cause widespread, long-term losses with economic costs to the United States estimated at \$1-2 trillion and a recovery time of four to ten years.²⁰ The NERC Interim GMD Report concluded, on the other hand, that the worst-case scenario is “voltage instability and subsequent voltage collapse,” and cites as an example the 1989 Hydro-Québec blackout.²¹ While the conclusions of these reports differ significantly, our proposed action is warranted by even the lesser consequence of a projected widespread blackout without long-term, significant damage to the Bulk-Power System. Taking steps to prevent such blackouts is consistent with maintaining the reliable operation of the Bulk-Power System.²²

6. Given the potentially severe, wide-spread impact to the reliable operation of the Bulk-Power System from GMD events and the absence of existing Reliability Standards to address it, the Commission proposes to direct the ERO to file with the Commission for

¹⁹ *Id.* at pages 3-25, 3-26.

²⁰ National Research Council of the National Academies, *Severe Space Weather Events—Understanding Societal and Economic Impacts: A Workshop Report* at 4 (2008) (NAS Workshop Report), available at <http://www.nap.edu/catalog/12507.html>.

²¹ NERC Interim GMD Report at 69.

²² 16 U.S.C. 824o(a)(4) (“The term ‘reliable operation’ means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”).

approval Reliability Standards that address this reliability gap. In proposing to address the risks posed by GMDs in two stages, the Commission finds that there are Reliability Standards that the ERO can develop and file quickly (i.e., requiring GMD operational procedures) to mitigate the effects of GMDs while it develops other Reliability Standards that require owners and operators of the Bulk-Power System to assess the potential impact of GMDs on Bulk-Power System equipment and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs identified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.²³

7. We recognize that, depending on the results of the initial and on-going assessments that would be required under this proposed rule, there could be substantial costs associated with some measures to protect against damage to the Bulk-Power System

²³ See *infra* PP 34-36.

from GMDs.²⁴ In determining that it is appropriate to issue this proposed rule, however, we have compared such costs against the societal harms, including the potential costs of equipment damage or prolonged blackouts, that could result from taking no action.²⁵

I. Background

A. Section 215 and Mandatory Reliability Standards

8. Section 215 of the FPA requires the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.²⁶ Once approved, the Reliability Standards may be enforced in the United States by the ERO, subject to Commission oversight, or by the Commission independently.

²⁴ For example, estimates for installing blocking devices on transformers range from \$100,000 to \$500,000 for each affected transformer. *See* Foundation for Resilient Societies, Comments on Advance Notice of Proposed Rulemaking (ANPR) of the Nuclear Regulatory Commission Relating to the Prevention and Mitigation of Station Blackout, filed in Docket No. AD12-13-000, at 13 (May 4, 2012) (citing \$500,000 installed costs per transformer); MITRE Corp., Impacts of Severe Space Weather on the Electric Grid, at 66 (November 2011) (citing \$100,000 cost for neutral-current-blocking-capacitors per transformer), *available at* <http://www.fas.org/irp/agency/dod/jason/spaceweather.pdf>.

²⁵ For example the estimated total cost of the August 2003 four-day blackout in the United States is between \$4 billion and \$10 billion, with the Department of Energy calculating the total cost to be \$6 billion. Electricity Consumers Resource Council, The Economic Impacts of the August 2003 Blackout, *available at* <http://www.elcon.org/Documents/EconomicImpactsOfAugust2003Blackout.pdf>. *See also supra* P 5 (citing estimates by the National Research Council of the National Academies of potentially \$1-2 trillion in economic costs from a severe GMD event).

²⁶ 16 U.S.C. § 824o (2006).

9. Pursuant to section 215(d)(5) of the FPA, the Commission has the authority, upon its own motion or upon complaint, to order the ERO to submit to the Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to carry out section 215 of the FPA.²⁷

B. Studies of GMD Events on the Bulk-Power System

10. The impact of GMDs on the Bulk-Power System has been evaluated in several government-sponsored studies and NERC reports. The EMP Commission issued reports assessing the threat to the United States from Electromagnetic Pulse (EMP) attack in 2004 and 2008, which also addressed the effects of geomagnetic storms on the electric power infrastructure.²⁸ The NAS Workshop Report addressing the impact of severe space weather events was released in 2008. The Oak Ridge National Laboratory issued the Oak Ridge Study on the effects of electromagnetic pulses on the Bulk-Power System in January 2010. The NERC HILF Report on high-impact, low-frequency risks to the Bulk-Power System was issued in June 2010.²⁹ In February 2012, NERC issued the NERC Interim GMD Report evaluating the effects of GMDs on the Bulk-Power System.

²⁷ 16 U.S.C. 824o(d)(5); 18 CFR 39.6(f) (2012).

²⁸ These reports are accessible at the Commission to Assess the Threat to the United States from Electromagnetic Pulse (EMP) Attack website at <http://www.empcommission.org/>.

²⁹ The HILF Report was prepared by NERC, Department of Energy, and a steering committee comprised of industry and risk experts and was approved by the NERC Board of Trustees on May 17, 2010. *HILF Report* at 2.

11. The Commission conducted a staff-led Technical Conference on April 30, 2012 to discuss the effects of GMDs on the reliable operation of the Bulk-Power System. NERC, government agencies, industry stakeholders, and other interested entities attended the Technical Conference and submitted post-Technical Conference comments.

C. Effects of GMD Events on the Bulk-Power System

12. The interaction of the Earth's magnetic field and solar events can cause low frequency GICs to flow along the surface of the Earth and in the oceans. Reliability issues arise when GICs enter the Bulk-Power System from the Earth. Since many Bulk-Power System transformers are grounded, the GIC appears as electrical current to the Bulk-Power System and flows through the ground connection and conductors, such as transformers and transmission lines.³⁰

13. GICs can cause transformer cores to become "saturated," resulting in loss of reactive power (VARs), the introduction of harmonic distortions, and possible physical damage to the transformer.³¹ GICs enter the Bulk-Power System through the grounded neutrals of transformers and are responsible for forcing their metal cores into saturation.³²

³⁰ Oak Ridge National Laboratory, *Electromagnetic Pulse: Effects on the U.S. Power Grid (Meta-R-322)* at page 1-1 (January 2010) (*Oak Ridge Study 322 Report*), available at http://www.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-322.pdf.

³¹ *HILF Report 70-71*. Harmonics are currents or voltages with frequencies that are integer multiples of the fundamental power frequency (i.e., 60 Hz in the United States). See Northeast Power Coordinating Council, Inc. Glossary of Terms, available at <https://www.npcc.org/Standards/Directories/Glossary%20of%20Terms.pdf>. They can cause overcurrent relays to automatically trip components (e.g., capacitor banks and static VAR compensators) from service. *HILF Report* at 71. Automatic removal of such components can further exacerbate system voltages already reduced by the GIC-related

A primary effect of saturation is the potential for transformer damage through the overheating of internal components.³³ Saturation is also responsible for secondary effects, such as the production of harmonics that are not present during normal Bulk-Power System operation and for substantially increasing the transformer's absorption of reactive power from the system, thus requiring significant amounts of additional voltage support to compensate for reactive power absorption. Harmonic production and reactive power absorption may interfere with normal system operations creating secondary effects on other Bulk-Power System facilities. These primary and secondary effects can occur almost simultaneously over a large geographic area, resulting in a multiple contingency outage that has the potential to cascade across the Bulk-Power System.³⁴

14. The Oak Ridge Study identified factors that determine the severity of GMD events, including: (1) location and strength of the underlying solar event; (2) ground conductivity in the affected locations (i.e., the geology of the location); (3) orientation of

absorption of reactive power.

³² *Oak Ridge Study 322 Report* at pages 1-1, 7-11.

³³ *HILF Report* at 70 ("Transformers experience excessive levels of internal heating brought on by stray flux when GICs cause the transformer's magnetic core to saturate and spill flux outside the normal core steel magnetic circuit. Previous well-documented cases have noted heating failures that caused melting and burn-through of large-amperage copper windings and leads in these transformers (Figure 9)."); *Oak Ridge Study 319 Report* at page 2-29 ("Also of note from this particular [March 1989] storm is strong evidence that GIC-induced half-cycle saturation of transformers can indeed produce enough heat to severely damage or even destroy exposed large power transformers.").

³⁴ *HILF Report* at 71-72.

the transmission lines; (4) length of transmission lines; and (5) grid construction.³⁵ A solar disturbance can cause near-simultaneous, multi-point failures that can trigger collapse of the Bulk-Power System.³⁶

II. Discussion

15. As discussed below, the Commission finds that there is a gap in the Reliability Standards regarding GMDs. Therefore, in order to carry out section 215 of the FPA, the Commission proposes to direct the ERO to develop and file for approval Reliability Standards that address the potentially severe, wide-spread impact of GMD events on the reliable operation of the Bulk-Power System.

16. We propose that the ERO develop and file the GMD Reliability Standards in two stages. In the first stage, within 90 days of the effective date of a final rule in this proceeding, the Commission proposes to direct NERC to file one or more Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System. In the second stage, the Commission proposes to direct NERC to file one or more Reliability Standards, within six months of the effective date of a final rule in this proceeding, that require owners and operators of the Bulk-Power System to assess the impact of GMDs on Bulk-Power System equipment

³⁵ *Oak Ridge Study 319 Report* at page 2-5.

³⁶ *Id.* at pages 4-1, 4-2. One example cited in the Oak Ridge Study is the March 13, 1989 solar disturbance that triggered the collapse of the Hydro-Québec power grid, which went from normal to a situation where it sustained seven contingencies in an elapsed time of 57 seconds. *Id.*

and the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs identified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.³⁷

17. In proposing to direct the ERO to submit Reliability Standards that address the impact of GMD events on the reliable operation of the Bulk-Power System, we are not proposing specific requirements or otherwise pre-judging what the ERO may eventually submit. Instead, we identify concerns that we believe should be addressed in any GMD Reliability Standards. We expect the ERO to support its proposed Reliability Standards and explain how they address the Commission's concerns.

³⁷ The second stage Reliability Standards would not require owners and operators of the Bulk-Power System to protect the Bulk-Power System beyond what is found to be required based on the initial and ongoing assessments.

A. Reliability Standards Requiring Operational Procedures

18. Requiring operational procedures, while not a complete solution, constitutes a first step to addressing the GMD reliability gap because they can be implemented relatively quickly.³⁸ The Commission does not propose to require the ERO or owners and operators of the Bulk-Power System to adopt any particular operational procedures. Owners and operators of the Bulk-Power System are the most familiar with the equipment and system configurations. Accordingly, we propose that the ERO file one or more Reliability Standards requiring owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System based on the following guidance.

19. Operational procedures may help alleviate abnormal system conditions due to transformer absorption of reactive power during GMD events, helping to stabilize system voltage swings, and may potentially isolate some equipment from being damaged or misoperated. The NERC Interim GMD Report identifies examples of operational procedures to mitigate GMD events (i.e., the effects of GICs), including: reduction of equipment loading (e.g., by starting off-line generation), unloading the reactive load of operating generation, reductions of system voltage, and system and/or equipment

³⁸ NERC Interim GMD Report at 79 (“Operating procedures are the quickest way to put in place actions that can mitigate the adverse effects of GIC on system reliability ... Both system operating and transmission owner organizations need to have appropriate procedures and training in place.”).

isolation through reconfiguration of the transmission system.³⁹ Some entities already have operational procedures to mitigate the effect of GICs on the Bulk-Power System utilizing system resources.⁴⁰ The Commission expects that the ERO and owners and operators of the Bulk-Power System will draw on industry's experience in developing and implementing existing operational procedures. Given that experience, we propose to direct NERC to file, within 90 days of the effective date of a final rule in this proceeding, proposed Reliability Standards that require the development and implementation of operational procedures. While this deadline is aggressive, mandatory and enforceable Reliability Standards requiring owners and operators to implement operational procedures should be established quickly to afford some level of uniform protection to the Bulk-Power System against GMD events. As discussed above, the impact of GMDs on the Bulk-Power System has been studied extensively for many years, laying the foundation for the prompt development of these first stage Reliability Standards. Moreover, the fact that operational procedures are already in place in some areas should allow for faster development and implementation of these Reliability Standards.

20. While the proposed Reliability Standards should not necessarily specify what operational procedures must be adopted, the ERO should give owners and operators of

³⁹ NERC Interim GMD Report at 80-81.

⁴⁰ See, e.g., PJM Interconnection, L.L.C., Manual 13: Emergency Operations at 47, *available at* <http://www.pjm.com/~media/documents/manuals/m13.ashx>; Northeast Power Coordinating Council, Inc., Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems, *available at* <https://www.npcc.org/Standards/Procedures/c-15.pdf>.

the Bulk-Power System guidance as to what procedures have been or are expected to be effective in mitigating the effects of GMDs consistent with the reliable operation of the Bulk-Power System. Moreover, the proposed Reliability Standards should address the coordination of operational procedures among responsible entities across regions.⁴¹

Since there could be potential equipment damage resulting from a GMD event, the proposed Reliability Standards should also address operational procedures for restoring GMD-impacted portions of the Bulk-Power System that take into account the potential for equipment that is damaged or out-of-service for an extended period of time.

21. We do not propose to direct a specific implementation schedule for the proposed Reliability Standards, but the Commission encourages the ERO to require owners and operators of the Bulk-Power System to implement the required operational procedures 90 days after Commission approval of the Reliability Standards. Following implementation, the Commission proposes to require NERC to provide periodic reports assessing the effectiveness of the operational procedures in mitigating the effects of GMD events. In addition, NERC should periodically review the required operational procedures and recommend to owners and operators that they incorporate lessons-learned and new research findings.

22. In addition to developing Reliability Standards that require operational procedures during the first stage, the Commission also proposes to accept aspects of the “Initial

⁴¹ NERC Interim GMD Report at 79 (“The [operating] procedures of these organizations need to be coordinated with each other and with their neighboring organizations.”).

Actions” proposal set forth in NERC’s May 21, 2012 post-Technical Conference comments. Specifically, NERC proposed to “identify facilities most at-risk from severe geomagnetic disturbance” and to “conduct wide-area geomagnetic disturbance vulnerability assessment.”⁴² As noted in NERC’s comments regarding the vulnerability assessments, special attention would be given to evaluating critical transformers (e.g., step-up transformers at large generating facilities). We agree with NERC that critical Bulk-Power System facilities should be evaluated for GMD vulnerability as an initial action. In addition, as part of the initial action, special attention should be given to those Bulk-Power System facilities that provide service to critical and priority loads.⁴³ The Commission, therefore, proposes to direct NERC to conduct this “initial action” simultaneously with the development and implementation of the first stage GMD Reliability Standards. The Commission seeks comment from NERC and other interested entities on all aspects of this proposal.

⁴² NERC Comments at 8-9 (“As the first step in identifying the risk of geomagnetic disturbance to the bulk power system, NERC intends to complete a system-wide vulnerability assessment ... special attention will be given to the evaluation of critical transformers, such as generator step-up units at large generating facilities ... a high level review will be conducted to identify and classify the at-risk population based on existing peer-reviewed research. This assessment will be based on a high level screening approach that will include transformer design, condition, geology and geomagnetic location.”).

⁴³ The NERC Severe Impact Resilience Task Force identified critical and priority loads in a report. See *Severe Impact Resilience: Considerations and Recommendations* at 26 (Accepted by NERC Board of Trustees on May 9, 2012), *available at* http://www.nerc.com/docs/oc/sirtf/SIRTF_Final_May_9_2012-Board_Accepted.pdf.

B. Second Stage Reliability Standards

23. To address GMDs comprehensively, the Commission proposes to direct NERC to develop, in a second stage, Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of GMDs on Bulk-Power System equipment and on the Bulk-Power System as a whole. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs identified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit. While the Commission proposes to direct the ERO to submit the proposed second stage Reliability Standards within six months of the effective date of a final rule in this proceeding, the Commission seeks comment on the feasibility of a six-month deadline.
24. We propose to direct the filing of these second stage GMD Reliability Standards because of two concerns with relying on operational procedures alone: (1) owners and operators of the Bulk-Power System may not have enough time to initiate effective

operating procedures after being warned of a GMD event; and (2) operational procedures may not prevent permanent damage to Bulk-Power System equipment.⁴⁴ Current GMD forecasting methods provide limited time for operators to react once a GMD warning is issued.⁴⁵ Even with enough time to react, the Oak Ridge Study found that, given a large enough GMD event, operational procedures are unlikely to provide the substantial levels of GIC reduction needed to limit the potential for permanent damage to transformers.⁴⁶ The Oak Ridge Study and the HILF Report also found that widespread damage to Bulk-Power System transformers could result in prolonged outages.⁴⁷

⁴⁴ NERC Interim GMD Report at 10 (“These warning can be received as short as 30 minutes before the onset of an impending geomagnetic storm.”). At the April 30, 2012 Technical Conference, Mr. Murtagh, Program Coordinator at the National Oceanic and Atmospheric Administration’s Space Weather Prediction Center, stated that a warning is issued when a GMD event reaches the NASA Advanced Composition Explorer (ACE) satellite and at that point, in some cases, it could be 20 or 30 minutes before the event reaches the Earth’s magnetic field. April 30, 2012 Technical Conference Tr. 170:5-22 (Murtagh).

⁴⁵ Mr. Pugh, from the U.S. Department of Homeland Security’s Interagency Programs Office Science & Technology Directorate, stated that the operators in the 1989 Hydro-Québec blackout only had 90 seconds to react, which was insufficient to “prevent a massive blackout and significant equipment damage.” April 30, 2012 Technical Conference Tr. 12:4-7 (Pugh).

⁴⁶ *Oak Ridge Study 322 Report* at pages ix and 1-1.

⁴⁷ *HILF Report* at 12 (“The physical damage of certain system components (e.g. extra-high-voltage transformers) on a large scale, as could be effected by any of these threats, could result in prolonged outages as procurement cycles for these components range from months to years.”); *Oak Ridge Study 319 Report* at pages 2-33, 2-34 (“An especially large storm or GIC event could plausibly create the potential for widespread failure of many exposed transformers and hamper rapid restoration capabilities. In extreme cases, where replacements may take months, a situation may exist where the demand for electric service can only be partially supplied, raising the prospect of rationing and rotating blackouts to regions that are unable to be fully served.”).

25. We recognize that the NERC Interim GMD Report concludes that a prolonged blackout due to extensive damage to Bulk-Power System transformers is less likely than voltage instability due to increased reactive power consumption and loss of reactive power support, which can lead to blackouts like the 1989 Hydro-Québec event.⁴⁸ The Commission's proposed two-stage approach recognizes this difference by focusing first on the development of Reliability Standards requiring operational procedures in a relatively short time frame. The Commission proposes to give NERC and owners and operators of the Bulk-Power System more time to perform, in the second stage, initial and on-going assessments. Based on those assessments, the Reliability Standards would require owners and operators to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. This plan cannot be limited to operational procedures or enhanced training alone, but should, subject to the needs identified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, or location of specific equipment. These strategies could include automatically blocking geomagnetically induced currents from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit. Moreover, although the NOPR proposes that the second stage

⁴⁸ NERC Interim GMD Report at vi.

Reliability Standards be filed within six months of the effective date of the final rule, we seek comment on the feasibility of that deadline.

26. Below, we offer guidance on the assessments of Bulk-Power System vulnerability to GMDs and potential measures for automatically protecting critical or vulnerable components. In addition, recognizing the potential for substantial investments of time and resources to implement these Reliability Standards, we offer guidance on an implementation schedule, which will likely consist of an extended, multi-phase process. The Commission seeks comment from NERC and other interested entities on all aspects of this proposal.

1. GMD Vulnerability Assessments of the Bulk-Power System

27. The Commission proposes to direct the ERO to develop Reliability Standards that require owners and operators of the Bulk-Power System to conduct vulnerability assessments to determine how critical or vulnerable Bulk-Power System components react to simulated GICs of varying intensities.⁴⁹ The Commission proposes to direct the ERO to consider the following parameters as it develops the Reliability Standards.⁵⁰

⁴⁹ To accurately simulate the impact of GMDs on the Bulk-Power System, the assessments should consider the impact of GICs that may enter the system through transformers that are not treated as part of the bulk electric system and any impact that the non-bulk electric system transformers may have on the reliability of the Bulk-Power System. We do not propose, however, that equipment falling outside of our jurisdiction would be required to be protected under the proposed Reliability Standard.

⁵⁰ The vulnerability assessments in the second phase Reliability Standards are distinct from the “initial action” evaluations, discussed above, which NERC proposed to do and we propose to have NERC conduct simultaneous with the development and implementation of the first phase Reliability Standards. We expect, however, that the

(continued...)

28. First, the Reliability Standards should contain uniform evaluation criteria for owners and operators to follow when conducting their assessments. As the Commission noted with respect to other reliability assessments, uniformity increases the accuracy of transmission system reliability assessments and consequently enhances overall reliability.⁵¹

29. Second, the assessments should, through studies and simulations, evaluate the primary and secondary effects of GICs on Bulk-Power System transformers, including the effects of GICs originating from and passing to other regions.

30. Third, the assessments should evaluate the effects of GICs on other Bulk-Power System equipment, system operations, and system stability, including the anticipated loss of critical or vulnerable devices or elements resulting from GIC-related issues.⁵²

31. Fourth, in conjunction with assessments by owners and operators of their own Bulk-Power System components, wide-area or Regional assessments of GIC impacts should be performed. A severe GMD event can cause simultaneous stresses at multiple

analyses performed in the “initial action” evaluations will be used to quickly identify and protect the most critical and vulnerable Bulk-Power System components once the second stage Reliability Standards become effective.

⁵¹ *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1298, *order on reh’g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

⁵² The Oak Ridge Study assessment included GMD modeling, simulation and review of storm impacts, power grid GIC flows and reactive power demands, transformer heating and risk of potential damage to transformers. *See generally Oak Ridge Study 319 Report*.

locations on the Bulk-Power System, potentially resulting in a multiple-outage event.⁵³

In predicting GIC flows, it is necessary to take into consideration the network topology as an integrated whole (i.e., on a wide-area basis).⁵⁴

32. Fifth, the assessments should be periodically updated, taking into account new facilities, modifications to existing facilities, and new information, including new research on GMDs, to determine whether there are resulting changes in GMD impacts that require modifications to Bulk-Power System mitigation schemes.

33. The Commission seeks comments from NERC and other interested entities on all aspects of this proposal.

2. **Automatic GIC Blocking for Critical or Vulnerable Bulk-Power System Components**

34. While we do not propose to require a particular solution in the second stage Reliability Standards to address GMDs, we expect that some assessments will demonstrate that automatic blocking is necessary in some instances. The Commission, above, proposes to direct the ERO to develop Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement a plan so that instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, will not occur as a result of a GMD. Automatic blocking measures address the major concerns with relying exclusively on operational procedures to mitigate GMDs (i.e., the

⁵³ *Oak Ridge Study 319 Report* at pages A1-1, A1-2.

⁵⁴ *Id.* at page 1-17.

short period of time to react to a GMD event and the potential consequences of not reacting fast enough). Blocking can prevent the flow of GICs through power transformers and the Bulk-Power System.⁵⁵ Eliminating GICs in transformers prevents transformer core saturation and, thus, mitigates or prevents the effects of GMDs on the Bulk-Power System (i.e., transformer overheating, reactive power absorption, and harmonic generation).

35. The Commission does not propose to direct the ERO to require a particular automatic blocking technology, where blocking is necessary. Instead, the Commission proposes to direct the ERO to identify in the proposed Reliability Standards what would constitute appropriate automatic blocking measures. In defining what is an appropriate blocking measure, the ERO should address: (1) its feasibility and effectiveness; and (2) its ability to operate without adversely impacting the reliable operation of the Bulk-Power System. The Commission proposes that the Reliability Standards should include a means by which the ERO can verify that selected blocking measures are appropriate.

36. The use of automatic blocking devices, such as transmission line series capacitors and transformer neutral blocking, are possible measures.⁵⁶ These devices block or reduce the flow of GIC in a power grid.⁵⁷ Although not a means for blocking GICs, another possible option is to improve the “withstand” capability of Bulk-Power System

⁵⁵ NERC Interim GMD Report at 73.

⁵⁶ *Oak Ridge Study 322 Report* at ix-x.

⁵⁷ *Id.*

components. The “withstand” capability, in this context, refers to a component’s ability to withstand stresses imposed by GICs before suffering damage, but it does not prevent GICs from affecting the rest of the Bulk-Power System (e.g., it does not prevent the secondary effects of harmonics or increased reactive power consumption).⁵⁸ The ERO should consider whether the reliability goals of the proposed Reliability Standards can be achieved by a combination of automatic protection measures, including, for example, some combination of automatic blocking and improved “withstand” capability. In any event, the measures must be adequate to protect the reliability of the Bulk-Power System against the risks identified in the assessments.

37. The Commission seeks comments from NERC and other interested entities on all aspects of this proposal.

3. Implementation Schedule

38. The second stage Reliability Standards will likely require an extended, multi-phase implementation period given the time needed to conduct the required assessments and the time and cost of installing any required automatic protection measures. Although the Commission does not propose to direct the ERO to develop a specific implementation plan, we believe it would be appropriate for the proposed Reliability Standard to include an implementation schedule that requires owners and operators of the Bulk-Power System to prioritize implementation so that components considered vital to the reliable

⁵⁸ NERC Interim GMD Report at 67.

operation of the Bulk-Power System are provided with any necessary automatic protection measures in the earliest phase of the plan.⁵⁹

39. The Commission seeks comments from NERC and other interested entities on an implementation plan.

III. Information Collection Statement

40. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency rules. 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 these collections of information unless the collections of information display a valid OMB control number. The Paperwork Reduction Act (PRA) requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons, or contained in a rule of general applicability.

41. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the PRA. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, ways to enhance the quality, utility, and clarity of the information to be collected,

⁵⁹ For example, critical Bulk-Power System equipment identified by NERC in the first stage "initial actions" assessments, discussed previously, should be protected in the earliest phase of the implementation plan.

and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

42. The Public Reporting Burden and cost related to the proposed rule in Docket No. RM12-22-000 are covered by, and already included in, the existing FERC-725, Certification of Electric Reliability Organization; Procedures for Electric Reliability (OMB Control No. 1902-0225). FERC-725 includes the ERO's overall responsibility for developing Reliability Standards, such as the Reliability Standards for Geomagnetic Disturbances.

43. Internal review: The Commission has reviewed the proposed changes and has determined that the changes are necessary to ensure the reliability and integrity of the Nation's Bulk-Power System.

44. Interested persons may obtain information on the reporting requirements by contacting: 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 requirements of this rule 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 should be sent by e-mail to OMB at oir_submission@omb.eop.gov. Please reference OMB Control No. 1902-0225, FERC-725 and the docket number of this proposed rulemaking in your submission.

IV. Environmental Analysis

45. 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.⁶⁰ 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.⁶¹ The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

46. The Regulatory Flexibility Act of 1980 (RFA)⁶² generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities.

47. By only proposing to direct NERC, the Commission-certified ERO, to develop GMD Reliability Standards, this Notice of Proposed Rulemaking will not have a significant or substantial impact on entities other than NERC. The ERO develops and files with the Commission for approval Reliability Standards affecting the Bulk-Power System, which represents: (a) a total electricity demand of 830 gigawatts (830,000

⁶⁰ *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).

⁶¹ 18 CFR 380.4(a)(2)(ii).

⁶² 5 U.S.C. 601-612.

megawatts) and (b) more than \$1 trillion worth of assets. Therefore, the Commission certifies that this Notice of Proposed Rulemaking will not have a significant economic impact on a substantial number of small entities.

48. Any Reliability Standards proposed by NERC in compliance with this rulemaking will be considered by the Commission in future proceedings. As part of any future proceedings, the Commission will make determinations pertaining to the Regulatory Flexibility Act based on the content of the Reliability Standards proposed by NERC.

VI. Comment Procedures

49. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**. Comments must refer to Docket No. RM12-22-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

50. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at <http://www.ferc.gov>. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

51. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.

52. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

53. 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.

54. 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.

55. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference

Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

Kimberly D. Bose,
Secretary.



FACTS

NEWS

STATEMENT

BIOS

January 17, 2013

Commissioner Cheryl A. LaFleur

STATEMENT

FEDERAL ENERGY REGULATORY COMMISSION

Docket No. FA11-21-000

Statement of Commissioner Cheryl A. LaFleur on NERC 2012 Performance Audit

"Last night FERC and the North American Electric Reliability Corporation (NERC) issued a joint press release to announce that the Commission had approved a settlement between the FERC Office of Enforcement (OE) and NERC of all outstanding issues in the Office of Enforcement's 2012 performance of NERC.

"I was very pleased to support the settlement, and I am confident that the procedures NERC and OE have agreed to will strengthen NERC as an organization.

"I would like to thank both the OE staff at FERC and NERC for their work in reaching this settlement. I look forward to continuing to work with NERC to improve the reliability and security of the electric transmission grid."

From: [Kimberly Mielcarek](#)
To: [Kimberly Mielcarek](#)
Subject: NERC Announcement - FERC, NERC Reach Settlement on NERC 2012 Performance Audit
Date: Wednesday, January 16, 2013 6:06:29 PM

Announcement

FERC, NERC Reach Settlement on NERC 2012 Performance Audit

Click here for [Announcement](#), [Settlement](#)

WASHINGTON, DC – The Federal Energy Regulatory Commission (FERC) approved a settlement today between its Office of Enforcement and the North American Electric Reliability Corporation (NERC) to resolve all issues related to the findings and recommendations in Enforcement’s 2012 performance audit of the electric reliability organization

“We are pleased to have been able to reach agreement with the Commission on the audit recommendations,” said Gerry Cauley, president and chief executive officer at NERC. “As a learning organization, NERC appreciates the value of an external audit in improving the electric reliability organization’s internal processes and procedures. A strong and effective ERO supports our overall mission of ensuring the reliability of the bulk power system.”

For more information or assistance, please contact [Kimberly Mielcarek](#)

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

You are currently subscribed to nerc-info as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1312941-325654.1ca6f85fb1574a8515cc07df72d3bfe0@listserv.nerc.com



Federal Energy Regulatory Commission



News Release

January 16, 2013

Contacts: Craig Cano, FERC (202) 502-8680

Kimberly Mielcarek, NERC (202) 644-8058

FERC Docket No.: FA11-21-000

FERC Approves Settlement on NERC 2012 Performance Audit

The Federal Energy Regulatory Commission (FERC) today approved a settlement between its Office of Enforcement and the North American Electric Reliability Corporation (NERC) to resolve all issues related to the findings and recommendations in Enforcement's 2012 performance audit of the electric reliability organization.

"This settlement will help us at the Commission, and the industry through NERC, move on with the important work of overseeing the reliability of the nation's bulk electric system," FERC Chairman Jon Wellenghoff said. "Implementing these improvements will help to keep the focus on reliability."

"We are pleased to have been able to reach agreement with the Commission on the audit recommendations," said Gerry Cauley, president and chief executive officer at NERC. "As a learning organization, NERC appreciates the value of an external audit in improving the electric reliability organization's internal processes and procedures. A strong and effective ERO supports our overall mission of ensuring the reliability of the bulk power system."

The performance audit, commenced in August 2011 and conducted by Enforcement's Division of Audits, evaluated NERC's budget formulation, administration and execution, focusing on the costs and resources used to achieve its program objectives. The May 4, 2012 final audit report made findings of fact and 42 recommendations in 11 broad areas, including the NERC budget process, compensation and expenses, and NERC's role as the Electricity Sector Information Sharing and Analysis Center. NERC subsequently contested the audit report's findings and recommendations.

Under the settlement, Enforcement and NERC resolve all outstanding contested recommendations, which related to, among other things, unbudgeted expenditures, the granularity of NERC budget filings, and employee time and expense tracking. The settlement also sets forth a procedure for confirming progress and implementation of audit recommendations.

142 FERC ¶ 61,042
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony T. Clark.

North American Electric Reliability Corporation

Docket No. FA11-21-000

ORDER APPROVING SETTLEMENT AGREEMENT

(Issued January 16, 2013)

1. The Commission approves the attached Settlement Agreement between the Office of Enforcement (Enforcement) and the North American Electric Reliability Corporation (NERC, and together with Enforcement, the Parties). This Order is in the public interest because it comprehensively resolves all outstanding issues between the Parties related to Enforcement's findings and recommendations arising out of its 2012 performance audit of NERC.

I. Background

2. Section 215 of the Federal Power Act (FPA) requires the Commission to certify an Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.¹ In July 2006, the Commission certified NERC as the ERO.²

3. On August 22, 2011, Enforcement's Division of Audits informed NERC by letter that it was commencing a performance audit of NERC pursuant to FPA section 215.³ The audit letter stated that the performance audit would evaluate "NERC's budget formulation, administration, and execution[,] . . . will focus on the costs and resources

¹ 16 U.S.C. § 824o (2006).

² *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007), *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).

³ 16 U.S.C. § 824o (2006); 18 C.F.R. § 39.2(d) (2012).

used to achieve program objectives . . . [and] will cover the period from August 23, 2006 to the present.”⁴ The performance audit constituted the first Commission audit of the ERO.

4. On May 4, 2012, Enforcement issued its performance audit report (Audit Report) by delegated letter order. The delegated letter order stated that the Audit Report covered the period from August 23, 2006 to March 14, 2012, and contained 11 findings of fact and 42 recommendations. The delegated letter order stated that NERC had 30 days to notify the Commission as to whether it would seek a hearing, such as a paper or trial type hearing, on issues in the Audit Report contested by NERC. The delegated letter order further indicated that it constituted a final agency action with respect to any uncontested issues in the Audit Report and that NERC could seek rehearing before the Commission on the uncontested audit findings and recommendations within 30 days.

5. On May 15, 2012, NERC filed with the Commission a proposed schedule for a hearing process to address the Audit Report’s 42 recommendations. Also on May 15, 2012, NERC filed a request for rehearing of the delegated letter order issued by Enforcement, arguing that all of the recommendations should be treated as contested and subject to the hearing procedures proposed by NERC. NERC stated that its request for rehearing would be rendered moot if the Commission adopted NERC’s proposed hearing process.

6. On June 4, 2012, the Commission issued an Order on Procedures adopting NERC’s proposed process with modifications and establishing a paper hearing to address all 42 audit recommendations as well as disputed factual findings.⁵

7. Pursuant to the Order on Procedures, NERC filed an initial brief on July 19, 2012 (Initial Brief). On August 16, 2012, the California Public Utilities Commission filed a response. On August 20, 2012, non-decisional Enforcement staff filed a response to the Initial Brief (Staff Reply Brief) and the American Public Power Association, Edison Electric Institute, Electric Power Supply Association, Electricity Consumers Resource Council, Large Public Power Council, National Rural Electric Cooperative Association, and Transmission Access Policy Study Group filed a joint response. On September 10, 2012, NERC filed a reply brief (NERC Reply Brief).

⁴ The August 22, 2011 audit letter to NERC is available on the Commission’s eLibrary document retrieval system in Docket No. FA11-21-000.

⁵ *North American Electric Reliability Corp.*, 139 FERC ¶ 61,179 (2012) (Order on Procedures). In the Order on Procedures, the Commission created a separation of functions among Office of Enforcement staff, designating certain employees as non-decisional.

8. On November 2, 2012, the Commission issued an Order Accepting 2013 Business Plan and Budget of the North American Electric Reliability Corporation and Ordering Compliance Filing, which, *inter alia*, ruled on disputed Audit Report Recommendation Nos. 37 and 38 and required NERC to submit in the above-captioned docket by February 1, 2013 proposed written criteria for determining whether a reliability activity is eligible to be funded under FPA section 215.⁶ The Commission stated it will address NERC's proposed written criteria in the above-referenced docket after NERC makes the February 1, 2013 filing required in the 2013 Budget Order. The Commission's action in the 2013 Budget Order was without prejudice to any future rulings on the other Audit Report findings and recommendations.⁷

II. Audit Report Findings and Recommendations

9. In the Audit Report, Enforcement staff found 11 areas in which NERC's performance with respect to its budget formulation, administration, and execution could be enhanced: Retirement Plans; NERC Activities; NERC Budget Process; Time Reporting and Accounting System; Employee Compensation; Board of Trustees Compensation and Expenses; Standard for Determining the Reasonableness of Expenses; NERC Critical Infrastructure Protection Program; NERC as the Electricity Sector Information Sharing and Analysis Center (ES-ISAC); Employee Entertainment; and NERC Oversight of Regional Entities' Budgets.

10. In its Initial Brief, NERC contested all of the Audit Report's findings and 22 of its recommendations. Staff in its Reply Brief accepted or conditionally accepted 10 of NERC's proposed revised recommendations. NERC's Reply Brief accepted many of Enforcement staff's proposed conditions. At the conclusion of briefing, all factual findings remained in dispute and 13 recommendations had not been fully resolved.

III. Settlement Agreement

11. Enforcement and NERC resolve all matters between them related to the findings and recommendations arising out of Enforcement's 2012 performance audit of NERC by means of the attached Settlement Agreement.

12. The Settlement Agreement indicates that nothing in the Settlement Agreement limits the Commission's ability to determine the sufficiency of the criteria NERC will submit to the Commission on February 1, 2013 regarding section 215 of the FPA or whether any NERC activity is or is not eligible for funding under section 215 of the FPA. In approving the Settlement Agreement, the Commission makes no finding as to the

⁶ *North American Electric Reliability Corp.*, 141 FERC ¶ 61,086, at PP 29-31 (2012) (2013 Budget Order).

⁷ *Id.* P 29.

sufficiency of the criteria NERC will submit to the Commission or whether any NERC activity is or is not eligible for funding under section 215 of the FPA. The Commission will address those issues in a subsequent order.

13. NERC neither admits nor denies the findings of fact contained in the Audit Report.

14. In order to confirm implementation of the Settlement Agreement, Enforcement and NERC agree that NERC will submit to Enforcement's Division of Audits: (a) a plan for NERC's implementation of the Settlement Agreement and all Audit Report recommendations as revised by the mutual agreement of Enforcement and NERC in their pleadings in this proceeding and in the Settlement Agreement; (b) quarterly reports detailing NERC's progress toward implementing the Settlement Agreement and all recommendations; and (c) a report describing NERC's final implementation of the Settlement Agreement and all recommendations. The Settlement Agreement also provides that Enforcement will conduct a post-audit review of NERC's implementation of the Settlement Agreement and all recommendations.

The Commission orders:

The attached Settlement Agreement is hereby approved without modification.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric	)	Docket No. FA11-21-000
Reliability Corporation	)	

SETTLEMENT AGREEMENT

1. The staff of the Commission's Office of Enforcement (Enforcement) and the North American Electric Reliability Corporation (NERC) (collectively, the Parties) enter into this Settlement Agreement (Agreement) to comprehensively resolve all issues related to the findings and recommendations of Enforcement's 2012 performance audit of NERC in the above-referenced proceeding.

I. PROCEDURAL HISTORY

2. On August 22, 2011, the Office of Enforcement's Division of Audits commenced the first performance audit of NERC, the Commission-certified Electric Reliability Organization, pursuant to the Commission's authority under Section 215 of the Federal Power Act (FPA), 16 U.S.C. § 824o, and 18 C.F.R. part 39 (2012).¹ The audit evaluated NERC's budget formulation, administration, and execution, focusing on the costs and resources used to achieve NERC's program objectives, for the period August 23, 2006 to March 14, 2012.
3. The Division of Audits provided a draft audit report to NERC on March 23, 2012. NERC provided a response to the draft audit report on April 23, 2012. The final audit report was issued by delegated letter order on May 4, 2012 (Audit Report).² The Audit Report included findings of fact and forty-two recommendations in eleven areas.
4. On May 15, 2012, NERC filed a proposed schedule for a paper hearing process to address the Audit Report's recommendations. On June 29, 2012, the Commission

¹ See Letter from Norman C. Bay, Director, Office of Enforcement, to Gerry Cauley, NERC Chief Executive Officer (August 22, 2012) (Docket No. FA11-21-000) (notifying NERC of the initiation of the audit).

² *N. Am. Elec. Reliability Corp.*, Docket No. FA11-21-000 (May 4, 2012) (delegated letter order).

adopted NERC's proposed procedural schedule with modifications.³

5. In its July 19, 2012 Initial Brief, filed pursuant to the Order on Procedures, NERC disputed all of the Audit Report's findings and twenty-two of its recommendations. On August 20, 2012, Enforcement filed a Response to NERC's Initial Brief in which it accepted or conditionally accepted ten of NERC's proposed revised recommendations. NERC filed a Reply to Enforcement's Response on September 10, 2012 in which it accepted many of Enforcement's proposed conditions. At the conclusion of briefing, all factual findings remained in dispute and thirteen recommendations had not been fully resolved.
6. On November 2, 2012, the Commission issued an Order Accepting 2013 Business Plan and Budget of the North American Electric Reliability Corporation and Ordering Compliance Filing, *N. Amer. Elec. Reliability Corp.*, 141 FERC ¶ 61,086 (2012) (2013 Budget Order), in which it, among other things, ruled on disputed Audit Report Recommendation Nos. 37 and 38 relating to NERC's development of written criteria for determining whether a reliability activity is eligible to be funded under FPA Section 215. The Commission will address NERC's proposed written criteria in the above-referenced docket after NERC makes the February 1, 2013 filing required in the 2013 Budget Order.⁴

II. AGREEMENT

7. Audit Report Recommendation Nos. 2 and 3: Unbudgeted Expenditures

- (a) The Parties agree to the following revised Recommendation No. 2:

“Continue to make improvements in budget transparency that informs the Commission, the Board and stakeholders concerning the expenditure of funds approved for specific budgeted activities on unbudgeted activities, and implement guidelines governing such expenditures, including criteria for determining when Board and Commission approval is required.”

³ *N. Am. Elec. Reliability Corp.*, 139 FERC ¶ 61,179 (2012) (“Order on Procedures”).

⁴ The Parties acknowledge that nothing in this Agreement limits the Commission's ability to determine the sufficiency of the proposed criteria or whether any NERC activity is or is not eligible for funding under FPA Section 215.

- (b) With respect to implementation of Recommendation No. 2, the Parties agree that:
- (i) 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;
 - (ii) NERC will file for Commission review and approval Board-of-Trustees-approved proposals to expend \$500,000 or more from operating reserves designated for "unforeseen contingencies" (as that term is defined in NERC's Working Capital and Operating Reserve Policy (Reserve Policy)). Each such filing will include supporting materials in sufficient detail to justify the proposed expenditure. The filing will be deemed approved if the Commission does not act on it or issue a tolling order extending the time for Commission action within thirty days of the filing date.

The Parties agree that this requirement for Commission review and approval is triggered if any amount allocated from the unforeseen contingencies account of 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.

- (iii) NERC is not required to obtain prior Commission approval for any use of budgeted "working capital reserves" (as that term is defined in the Reserve Policy); and
- (iv) NERC is not required to obtain prior Commission approval for any expenditure of budgeted operating reserves for "known contingencies" (as that term is defined in the Reserve Policy) where operating reserves have been earmarked by NERC for the specific purposes of that expenditure in NERC's Commission-approved annual business plan and budget.

- (c) The Parties agree to delete Recommendation No. 3.
- (d) The provisions of Section 7(a), (b), and (c) are based on NERC's current Reserve Policy, which, *inter alia*, defines "working capital reserves," "operating reserves," "known contingencies" and "unforeseen contingencies." NERC will file proposed revisions to the Reserve Policy that would alter any of those definitions, or would change the Reserve Policy's requirement that all excess funds be added to the unforeseen contingency operating reserves and expended in accordance with the Policy's unforeseen contingency guidelines, for Commission review and approval.

8. Audit Report Recommendation No. 4: Granularity of Annual Budget Filings

- (a) The Parties agree to the following revised Recommendation No. 4:

"Increase the granularity of the NERC budget filings by identifying proposed budgeted expenditures, at a minimum, by the major activities to be undertaken by each program area."⁵

9. Audit Report Recommendation Nos. 9, 12 and 13: Tracking Expenses and Employee Time

- (a) The Parties agree to the following revised Recommendation No. 9:

"Utilize NERC's new time recording system to track and report employee time, at a minimum by the major activities to be undertaken by each program area."

- (b) The Parties agree to the following revised Recommendation No. 12:

"Develop and utilize written processes and procedures to allocate operating and other expenses to the major activities to be undertaken

⁵ The Parties agree that, throughout this Agreement, the term "major activities" shall have the meaning ascribed to that term in Paragraph 31 of the 2013 Budget Order. For purposes of implementation of Recommendation Nos. 4, 9 and 12, the Parties agree that Board of Trustees meetings will be one such "major activity."

by each program area using allocation method(s) that are supportable such that NERC can demonstrate that a given expense was reasonably allocated to one or more major activities.”

- (c) The Parties agree to the following revised Recommendation No. 13:

“Conduct a cost-benefit analysis of implementing a more detailed project level budgeting and accounting system and file such analysis with the Commission by March 31, 2014.”

- (d) In addition, NERC agrees to maintain its expense records as necessary to support the audit of its financial statements, its filings with FERC and the allocation of expenses contemplated by Section 9(b) above. In addition, to the extent a project level budgeting and accounting system is implemented as a result of the analysis contemplated by Section 9(c) above, NERC will maintain its expense records as required to support that system. These expense records, as well as records of employee time tracked pursuant to Section 9(a) above, will be readily accessible to NERC staff such that they can be gathered and provided to Commission staff within ten business days of a written request.

10. Audit Report Recommendation Nos. 22-24: Budgeting for Employee Expenses

- (a) The Parties agree to the following revised Recommendation No. 22: “Explicitly budget for employee rewards and recognition and entertainment expenses by including line items of sufficient granularity in the budget filings.”

- (b) The Parties agree to the following revised Recommendation No. 23:

“Use miscellaneous expense accounts to track expenses which are for employee rewards and recognition or entertainment separately from other business-related expenses in its accounting system.”

- (c) The Parties agree to the following revised Recommendation No. 24:

“Ensure rewards and recognition expenses and entertainment expenses are clearly and transparently presented to the Board, Commission, and stakeholders in the budget before these costs are incurred.”

- (d) With respect to implementation of Recommendation Nos. 22-24, NERC agrees to develop: (i) policies and procedures that identify the costs to be recorded as employee rewards and recognition; and (ii) policies and procedures for how NERC will provide such rewards and recognition. NERC will file these policies and procedures for Commission review no more than sixty days after they are finalized.

11. Audit Report Recommendation No. 25: Method of Board of Trustees Compensation

- (a) NERC agrees that (i) within ninety days of its receipt of the independent study that NERC has commissioned of Board of Trustees compensation, it will file a copy of the study for Commission review; and (ii) within thirty days after any final decision by the NERC Board with respect to the implementation of any recommendations set forth in the study, file with the Commission an explanation of the Board's decision with respect to Board compensation. The Parties agree that this resolves their dispute regarding Recommendation No. 25.

12. Audit Report Recommendation Nos. 26-28: Board of Trustees Compensation Studies and Time Tracking

- (a) NERC agrees to: (i) continue to conduct annual reviews of Board of Trustees compensation, which will take into account Trustee time and participation in Board of Trustees activities; (ii) conduct periodic market studies regarding the structure and amount of Board of Trustees compensation; and (iii) include each such annual review and periodic market study with the following year's proposed business plan and budget. NERC acknowledges that in order to take Trustee time and participation into account in its annual reviews, it will need to maintain records regarding Trustee time and participation sufficient to meet its obligations to file a Form 990 with the Internal Revenue Service, including but not limited to accurately tracking Trustee attendance at all NERC Board and Committee meetings and conference calls and any other NERC-related meetings and conference calls attended by Trustees.
- (b) The Parties agree that their disputes regarding Recommendation Nos. 26-28 will be resolved by NERC's implementation of Section 12(a), above.

13. Audit Report Recommendation No. 29: Expenses in Connection with Board of Trustees Meetings

- (a) The Parties agree that their dispute regarding Recommendation No. 29 will be resolved by NERC's implementation of the provisions of Sections 8 and 9, above.

14. Audit Report Recommendation Nos. 39-42: NERC's Role as the Electricity Sector Information Sharing and Analysis Center

- (a) The Parties agree to the following revised Recommendation No. 39:

"Initiate an open and transparent process to provide opportunities for stakeholder input regarding NERC's role as the ES-ISAC, including (1) the impact, if any, on NERC's compliance-related activities of 'walling off' certain staff from the ES-ISAC activities; and (2) access of FERC staff to ES-ISAC information for situational awareness and compliance purposes."
- (b) The Parties agree that their disputes regarding Recommendation Nos. 40-42 will be resolved by NERC's implementation of revised Recommendation No. 39.

15. NERC neither admits nor denies the findings of fact contained in the Audit Report.

16. The Parties agree that the Order on Procedures rendered NERC's May 15, 2012 Request for Rehearing in Docket No. FA11-21-001 moot.

III. IMPLEMENTATION

17. In order to confirm implementation of this Agreement and all Audit Report recommendations as revised by the mutual agreement of the Parties in their pleadings in this proceeding and in this Agreement, the Parties agree as follows:

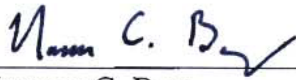
- (a) Within sixty days of the Effective Date, NERC will submit to Enforcement's Division of Audits a plan for NERC's implementation of this Agreement and all recommendations;
- (b) Within forty-five days of the end of a quarter, NERC will submit a report to Enforcement's Division of Audits detailing NERC's progress during the preceding quarter toward implementing this Agreement and all recommendations; and

- (c) NERC will submit to Enforcement's Division of Audits a report describing its final implementation of this Agreement and all recommendations no later than sixty days after NERC's fulfillment of all obligations thereunder. After receipt of such report, Enforcement will conduct a post-audit review of NERC's implementation of this Agreement and all recommendations.

IV. TERMS

- 18. This Agreement settles all matters between the Parties with respect to the contested Audit Report and comprehensively resolves all issues in the above-referenced proceeding related to the Audit Report's findings and recommendations.
- 19. The Effective Date of this Agreement shall be the date on which the Commission issues an order approving this Agreement in its entirety and without material modification.
- 20. This Agreement binds Enforcement and NERC and their agents, successors, and assigns. The Agreement does not create any additional or independent obligations on NERC, or any affiliated entity, its agents, officers, directors, or employees, other than the obligations identified in this Agreement. Enforcement and NERC do not intend for this Agreement to entitle any other party to any claim or right of any kind, it being the intent of Enforcement and NERC that this Agreement shall not be construed as a third-party beneficiary contract.
- 21. The signatories to this Agreement agree that they enter into the Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer, or promise of any kind by any member, employee, officer, director, agent, or representative of Enforcement or NERC has been made to induce the signatories or any other party to enter into the Agreement.
- 22. Unless the Commission issues an order approving this Agreement in its entirety and without material modification, the Agreement shall be null and void and of no effect whatsoever, and neither Enforcement nor NERC shall be bound by any provision or term of this Agreement, unless otherwise agreed to in writing by Enforcement and NERC.
- 23. Each of the undersigned warrants that he or she is an authorized representative of the entity designated, is authorized to bind such entity, and accepts this Agreement on the entity's behalf.
- 24. This Agreement may be executed in duplicate, each of which so executed shall be deemed to be an original.

Agreed to and Accepted:



Norman C. Bay
Director
Office of Enforcement

Jan. 15, 2013



Charles A. Berardesco
Senior Vice President
North American Electric Reliability
Corporation

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Revisions to Electric Reliability	)	Docket Nos. RM12-6-000
Organization Definition of Bulk Electric System	)	RM12-7-000
And Rules of Procedure	)	

**REQUEST FOR CLARIFICATION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION**

Pursuant to Rules 212 and 713, of the Federal Energy Regulatory Commission’s (“FERC” or the “Commission”) Rules of Practice and Procedure, 18 C.F.R. § 385.212, 385.713, the North American Electric Reliability Corporation (“NERC”)¹ requests clarification of the Commission’s December 20, 2012 Order on Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure (“Order No. 773”).²

NERC appreciates the Commission’s recognition in Order No. 773³ of NERC and the industry’s efforts to provide a technically grounded and legally supportable foundation for identifying elements and facilities that comprise the Bulk Electric System (“BES”). Similarly, NERC recognizes the Commission’s commitment to resolving this important issue and the time frame in which the Commission issued a final order following NERC’s initial submission of a revised definition of the Bulk Electric System (“BES Definition”). However, there are several areas where NERC requests the Commission to clarify its interpretation of the BES Definition in Order No. 773.

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. *North American Electric Reliability Corporation*, 116 FERC ¶ 61,062 (2006).

² *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012).

³ Order No. 773 at P 3.

I. EXECUTIVE SUMMARY

NERC respectfully requests the following:

(1) clarification of the Commission directive to revise Exclusion E3; and

(2) clarification of the Commission directives to:

(a) implement Exclusion E1 so that the exclusions for radial systems do not apply to tie-lines for BES generators identified in inclusion I2, and

(b) implement Exclusion E3 so that the exclusion for local networks does not apply to BES generator tie-lines operated at or above 100 kV.

First, NERC requests the Commission clarify the directive in Order No. 773 to remove the 100 kV minimum operating threshold language from Exclusion E3.⁴ NERC requests additional information and rationale regarding the technical justification for this directed modification in order to implement this directive appropriately.

Second, NERC requests the Commission clarify its directives to (a) implement Exclusion E1 so that the exclusions for radial systems do not apply to tie-lines for BES generators identified in inclusion I2, and (b) to implement Exclusion E3 so that the exclusion for local networks does not apply to BES generator tie-lines operated at or above 100 kV. NERC requests clarification in order to implement these directives appropriately.

II. BACKGROUND

NERC's BES Definition is an integral part of the NERC Reliability Standards and is included in the NERC Glossary of Terms Used in Reliability Standards.⁵ The Commission approved NERC's BES Definition in Order No. 693 with reservations.⁶ The Commission noted

⁴ Order No. 773 at P 155 ("we direct NERC to modify exclusion E3 to remove the 100 kV minimum operating voltage in the local network definition.").

its concern that the Bulk Electric System definition had the potential for gaps in coverage of facilities, and indicated that it would revisit the issue.⁷

In Order No. 743, the Commission directed NERC to undertake the process of revising the BES Definition to address the Commission's concerns about the broad discretion the former definition granted to Regional Entities to modify the definition without Commission or ERO oversight, and the Commission provided a suggested solution.⁸ Specifically, the Order directed the ERO to revise the definition of BES "through the NERC Standards Development Process to address the Commission's concerns."⁹ The Commission stated its belief that one effective way to address those concerns would be to eliminate the regional discretion contained in the current definition, which allows Regional Entities to define the term without Commission or ERO oversight; maintain the threshold contained in the current definition, which includes all facilities operated at or above 100 kV except defined radial facilities; and adopt an exemption process and criteria for excluding facilities that the ERO determines are not necessary to operate an interconnected electric transmission network. In Order No. 743-A, "the Commission emphasize[d] that Order No. 743 did not mandate or direct NERC to adopt a 100 kV bright-line threshold."¹⁰

On January 25, 2012, NERC submitted two petitions pursuant to the directives in Order No. 743: (1) NERC's proposed revision to the definition of "bulk electric system" which includes provisions to include and exclude facilities from the "core" definition; and (2) revisions

⁵ See Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

⁶ Order No. 693 at P 75.

⁷ *Id.* See also Order No. 693-A at P 19 (the Commission will continue to rely on NERC's definition of bulk electric system, with the appropriate regional differences, and the registration process until the Commission determines in future proceedings the extent of the Bulk-Power System").

⁸ *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 75 FR 72910 (Nov. 26, 2010), 133 FERC ¶ 61,150 (2010), *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011).

⁹ Order No. 743 at P 16.

¹⁰ Order No. 743-A at P 20.

to NERC's Rules of Procedure to add a procedure creating an exception process to classify or de-classify an element as part of the "bulk electric system." In Docket No. RM12-6-000, NERC filed a petition requesting Commission approval of a revised definition of "bulk electric system" in the NERC Glossary. The definition consists of a "core" definition and a list of facilities configurations that will be included or excluded from the "core" definition. NERC proposed the following "core" definition of bulk electric system:

Unless modified by the [inclusion and exclusion] lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

The Commission issued the BES Notice of Proposed Rulemaking ("NOPR") on June 22, 2012, and required that comments be filed within 60 days after publication in the *Federal Register*, or September 4, 2012.¹¹ While seeking comment on various provisions of NERC's petitions, the NOPR proposed to approve NERC's modification to the currently-effective definition of BES and changes to the Rules of Procedure to add the exception process. The NOPR also requested comment on the appropriate role for NERC and the Commission in the identification of BES facilities and elements. NERC submitted comments on September 4, 2012, and reply comments on September 19, 2012.¹²

The Commission issued Order No. 773 on December 20, 2012. Highlights of Order No. 773 include, the acceptance of NERC's revisions to its Rules of Procedure and establishment of a process pursuant to which an entity can seek a determination by the Commission whether facilities are "used in local distribution" as set forth in the FPA. Order No. 773 directs NERC:

¹¹ *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, 139 FERC ¶ 61,247 (June 22, 2012) ("NOPR").

¹² NERC's initial comments are available here: http://www.nerc.com/files/FINAL_Comments_BES_NOPR_complete.pdf and NERC's reply comments are available here: http://www.nerc.com/files/FINAL_BES_NOPR_Reply%20comments_clean.pdf.

(1) “to implement the exclusions for radial systems and local networks so that they do not apply to tie-lines for bulk electric system generators;” and (2) “to modify the local network exclusion to remove the 100 kV minimum operating voltage...”¹³

III. REQUEST FOR CLARIFICATION

A. The Commission Should Clarify its Directive to Remove the 100 kV Minimum Operating Threshold Language From Exclusion E3.

NERC requests the Commission clarify the directive in Order No. 773 to remove the 100 kV minimum operating threshold language from Exclusion E3 and the manner in which this directive should be implemented.¹⁴

The core BES Definition includes “all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher” and the “100 kV minimum operating voltage” language in Exclusion E1 simply mirrors this threshold determination and ensures that the BES Definition identifies the vast majority of BES Elements in a consistent manner that can be applied on a continent-wide basis.

Order No. 773 directs NERC to remove specific language in Exclusion E3 of the BES Definition. The Commission “direct[s] NERC to modify exclusion E3 to ***remove the 100 kV minimum operating voltage*** in the local network definition.”¹⁵

Exclusion E3 states:

E3 - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN’s emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load

¹³ Order No. 773 at P 4.

¹⁴ Order No. 773 at P 155 (“we direct NERC to modify exclusion E3 to remove the 100 kV minimum operating voltage in the local network definition.”).

¹⁵ Order No. 773 at P 155 (emphasis added).

and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

NERC interprets the directive to be effectuated in the following manner:

E3 - Local networks (LN): A group of contiguous transmission Elements operated at ~~or above 100 kV but~~ less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

NERC requests clarification as to whether this is a correct interpretation of the Commission's directive. While the outcome of the application of either Exclusion E1 or Exclusion E3 to Figures 3 and 5 is the same;¹⁶ (i.e., all elements other than Lines 1 and 2 are excluded from the BES Definition), NERC notes that the Commission's approach will entail the evaluation of significantly more facilities in applying Exclusion E3 and is administratively burdensome. NERC respectfully requests that the Commission clarify the basis and intent of this directive to allow NERC to implement this directive appropriately.

B. The Commission Should Clarify its Directives on Implementation of Exclusion E1 and Exclusion E3.

NERC requests the Commission clarify the directives in Order No. 773 in Paragraphs 164 and 214 to (i) "implement exclusion E1 so that the exclusions for radial systems do not apply to tie-lines for bulk electric system generators identified in inclusion I2" (P 164) and (ii) "implement exclusion E3 so that the exclusion for local networks does not apply to bulk electric system generator tie-lines operated at or above 100 kV" (P 214). The Commission does not state whether "implementation" applies to Phase 1 or Phase 2 of the BES Definition or *how*

¹⁶ Assuming that the relevant Exclusion criteria are met.

implementation would be effectuated without a change to the BES Definition. Specifically, NERC requests that the Commission clarify how these directives should be reconciled with the plain language of the Exclusions.

As a preliminary matter, NERC notes that the Commission's use of the term "tie-line" in the general sense is potentially confusing for stakeholders as "Tie Line" is a defined term in the NERC Glossary of Terms Used in Reliability Standards that refers to a "circuit connecting two Balancing Authority Areas."¹⁷ This could create additional complications with the implementation of the Commission's directive unless the Commission clarifies its use of this term.

Exclusion E1 applies to a group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher" that meet certain criteria. The Commission (at P 167) "directs NERC to implement exclusion E1 so that the exclusion for radial systems does not apply to tie-lines for bulk electric system generators identified in inclusion I2." Similarly, the Commission (at P 214) "directs NERC to implement exclusion E3 so that the exclusion for local networks does not apply to bulk electric system generator tie-lines operated at or above 100 kV".

NERC respectfully requests that the Commission reconcile these directives with the express language of the BES Definition. The concept of "tie-lines," as that term is being used by the Commission, appears nowhere in the express language of Exclusion E1 or Exclusion E3. The Commission acknowledges in Order No. 773 that "exclusion E1 as written does not prevent the radial tie-line operating at or above 100 kV from the high side of the step-up transformer to

¹⁷ See Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

the bulk electric system from being excluded...”¹⁸ NERC requests clarification in order to implement these directives appropriately.

IV. CONCLUSION

For the reasons set forth herein, NERC requests that the Commission clarify its directives with respect to Exclusion E3 and the implementation of Exclusion E1 and Exclusion E3.

Respectfully submitted,

/s/ Stacey Tyrewala

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability
Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Stacey Tyrewala
Attorney
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

*Counsel for the North American Electric
Reliability Corporation*

Dated: January 22, 2013

¹⁸ Order No. 773 at P 167 (emphasis added).

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 January, 2013.

/s/ Stacey Tyrewala
Stacey Tyrewala
*Attorney for North American Electric
Reliability Corporation*

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Mandatory Reliability Standards for the Bulk-Power System	)		Docket No. RM06-16-010 RM06-16-011
	)		

**QUARTERLY REPORT OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
ON STATUS OF DEVELOPMENT OF BAL-003**

On March 30, 2012, the North American Electric Reliability Corporation (“NERC”) filed with the Federal Energy Regulatory Commission (“FERC” or the “Commission”) a motion for an extension of time to submit a revised Resource and Demand Balancing (“BAL”) Reliability Standard on Frequency Response and Frequency Bias, BAL-003. On May 4, 2012, the Commission issued an order¹ establishing a compliance schedule for NERC to submit a revised BAL-003 consistent with the Commission’s directives in Order No. 693.² The Commission established a deadline of May 31, 2013, and directed the submission of informational reports on a quarterly basis describing “the progress NERC is making toward completing its analysis and research as well as the progress it is making in completing work on the other issues and filing a revised BAL-003-0 Reliability Standard by May 31, 2013.”³ The instant filing is submitted in compliance with the Commission’s directive in the May 4 Order.

¹ *Mandatory Reliability Standards for the Bulk-Power System*, 139 FERC ¶ 61,097 (2012)(“May 4 Order”).

² *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at PP 369-375, *order on reh’g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). *See also Mandatory Reliability Standards for the Bulk-Power System*, 130 FERC ¶ 61,218, *order on reh’g*, 131 FERC ¶ 61,136, *order on compliance filing*, 133 FERC ¶ 61,212 (2010).

³ May 4 Order at P 9.

I. Notices and Communication

Notices and communications with respect to this filing may be addressed to the following:⁴

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco*
Senior Vice President and General Counsel
Holly A. Hawkins*
Assistant General Counsel
Stacey Tyrewala*
Attorney
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

II. Attachments

Attachment A BAL-003-1, Frequency Response and Frequency Bias Setting

III. Status of BAL-003 Standard Development Efforts

The BAL-003-1, Frequency Response and Frequency Bias Setting, Reliability Standard was approved by stakeholders in December 2012 with a quorum of 86.19% and an approval rating of 76.53%. The standard will be presented to the NERC Board of Trustees for adoption in February 2013 and then will be filed with the appropriate regulatory authorities, including the Commission. NERC expects that it will meet the Commission's May 31, 2013 deadline as established in the May 4 Order.

⁴ Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

IV. Conclusion

The North American Electric Reliability Corporation respectfully requests that the Commission accept this Compliance Filing in accordance with the Commission's directives in the May 4 Order.

Respectfully submitted,

/s/ Stacey Tyrewala

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability
Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Stacey Tyrewala
Attorney
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

*Counsel for North American Electric Reliability
Corporation*

Dated: January 23, 2013

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 January, 2013.

/s/ Stacey Tyrewala

Stacey Tyrewala

*Attorney for North American Electric
Reliability Corporation*

Attachment A

BAL-003-1, Frequency Response and Frequency Bias Setting

Standard Development Roadmap

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

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on January 13, 2005.
2. The SAR was posted for industry comment from January 17, 2005 through February 17, 2005.
3. Reply comments and a revised SAR were posted for a second industry comment period from April 4, 2006 through May 3, 2006.
4. Reply comments and a revised SAR were posted for a third industry comment period from February 8, 2007 through March 9, 2007.
5. Standards Committee approved moving the project into the standards development phase on July 12, 2007.
6. The Standards Committee appointed the Standard Drafting Team on August 13, 2007.
7. The draft standard was posted for a 30 day formal comment period from February 4, 2011 through March 7, 2011.
8. The draft standard was posted for a 45-day formal comment period and a 10 day initial ballot from October 25, 2011 through December 8, 2011.

Proposed Action Plan and Description of Current Draft:

This is the third posting of the proposed standard and its associated documents for a 30 day formal comment period and a successive 10 day ballot, from October 5, 2012 through November 5, 2012.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments submitted within the comment period and with the successive ballot.	December, 2012
2. Conduct a recirculation ballot for ten days.	December, 2012
3. BOT adoption.	February, 2013

Definitions of Terms used in the Standard

Frequency Response Measure (FRM)

The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.

Frequency Response Obligation (FRO)

The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.

Frequency Bias Setting

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's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.

Frequency Response Sharing Group (FRSG)¹

A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.

¹ This term and definition is identical to the definition in BAL-012-1 proposed standard.

A. Introduction

Title: Frequency Response and Frequency Bias Setting

Number: BAL-003-1

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

Applicability:

1.1. Balancing Authority

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

1.2. Frequency Response Sharing Group

Effective Date:

1.3. In those jurisdictions where regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after Board of Trustees adoption.

1.4. In those jurisdictions where regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after Board of Trustees adoption.

B. Requirements

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

- R2.** Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*
- R3.** Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*
- 3.1** Less than zero at all times, and
- 3.2** Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.
- R4.** Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*
- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
 - The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

C. Measures

- M1.** Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.
- M2.** The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.
- M3.** The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of

the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity is the Compliance Enforcement Authority except where the responsible entity works for the Regional Entity. Where the responsible entity works for the Regional Entity, the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity), to be responsible for compliance enforcement.

1.2. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.3. Data 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 Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

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

1.4. Additional Compliance Information

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

2.0 Violation Severity Levels

R#	Lower VSL	Medium VSL	High VSL	Severe VSL
R1	The summation of the Balancing Authorities' FRM within an Interconnection was equal to or more negative than the Interconnection's IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection was equal to or more negative than the Interconnection's IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection did not meet its IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection did not meet its IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO
R2	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation

	Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.
R3	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%..
R4	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing

	Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

E. Regional Variance

None

F. Associated Documents

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

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

G. Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Complete Revision under Project 2007-12	Revision

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**NORTH AMERICAN ELECTRIC)
RELIABILITY CORPORATION) Docket No. RD13-2-000**

**REPLY COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION**

Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission (“FERC” or the “Commission”), the North American Electric Reliability Corporation (“NERC”) hereby provides reply comments in response to the comments submitted on January 8, 2013 by the PPL Companies in the above-captioned proceeding relating to NERC’s petition for approval of proposed Reliability Standard VAR-002-2b.

I. BACKGROUND

A. Procedural Background

On November 21, 2012, NERC submitted a petition for approval of proposed Reliability Standard VAR-002-2b. The proposed VAR-002-2b Reliability Standard ensures that generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection. On January 8, 2013, the PPL Companies submitted comments requesting that the Commission modify the Violation Severity Level (“VSL”) for Requirement R2.

B. Violation Severity Levels

Violation Severity Levels are used by NERC and the Regional Entities in the determination of a penalty for an individual violation of a requirement of a Reliability Standard.¹ Reliability Standards set forth requirements with which applicable entities must comply. Violation Severity Levels do not set forth requirements, but instead are post-violation measurements of the degree to which a requirement was violated.²

For purposes of Commission review, and as a useful tool in the future development of new, or revision of current Violation Severity Levels, the Commission developed four guidelines for evaluating the validity of Violation Severity Level assignments: (1) Violation Severity Level assignments should not have the unintended consequence of lowering the current level of compliance; (2) Violation Severity Level assignments should ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties; (3) Violation Severity Level assignments should be consistent with the corresponding requirement; and (4) Violation Severity Level assignments should be based on a single violation, not on a cumulative number of violations.³ These guidelines provide a consistent and objective means for assessing, the consistency, fairness and potential consequences of Violation Severity Level assignments.

II. COMMENTS

A. The Commission Should Reject the Proposed Modification to the VSL for Requirement R2.

As explained below, NERC submits that the Commission should reject the proposed modification to the VSL for Requirement R2 as this suggestion: (1) was raised and

¹ Note, Violation Severity Levels are not part of the Reliability Standard. See *North American Electric Reliability Corp.*, 123 FERC ¶ 61,284 at P 15 (2008).

² *Id.*

³ *Id.* at P 17.

considered during the standard development process, (2) is inconsistent with Commission guidelines for developing VSLs,⁴ and (3) is inconsistent with reliability principles.

1. The Proposed Modification to the VSL for Requirement R2 was Raised and Considered During the Standard Development Process.

The VSL for Requirement R2 currently reads:

When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for up to and including 45 minutes.

The PPL Companies propose the following language:

*When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 30 minutes up to and including 45 minutes.*⁵

Contrary to the contention of the PPL Companies, there was no “minor drafting oversight”⁶ as the language proposed by PPL Companies was explicitly considered and **rejected** by the standard drafting team during the standard development process. The Consideration of Comments report for VAR-002-2b states:

Several commenters suggested revisions to the VSL for Requirement R2. It was suggested that the timing elements of the VSLs be in-line with Requirement R3, which allows the Generator Operator 30 minutes to notify the Transmission Operator of changes in the status or capability of reactive resources. Requirement R2 does not build in a 30-minute window, as Requirement R3 does, so the SDT notes that **the VSLs must apply after a violation has been identified and therefore the “floor” must be at zero (not 30 minutes).**⁷

⁴ North American Electric Reliability Corp., 123 FERC ¶ 61,284 at P 17 (2008)(“[VSL] assignments should be consistent with the corresponding requirement”).

⁵ See Motion to Intervene and Comments of the PPL Companies at 4.

⁶ *Id.* at 2.

⁷ Available here at p. 1: http://www.nerc.com/docs/standards/sar/Consideration_of_Comments_2011-INT-02_2012July06_final.pdf (emphasis added).

Given that the revision proposed by PPL Companies was already expressly considered by the standard drafting team during the standard development process, NERC requests the Commission give deference to the technical expertise of the standard drafting team *not* to implement this change and reject the modification proposed by the PPL Companies.⁸

2. The Proposed Modification is Inconsistent With Commission Guidelines and Should be Rejected.

The modification proposed by the PPL Companies deviates from the NERC and Commission Guidelines on the development of VSLs and should therefore be rejected. Commission Guideline #3 for VSLs states that: “Violation Severity Level assignments should be consistent with the corresponding requirement.” The standard drafting team correctly recognized in the Consideration of Comments report that a revision such as that proposed by the PPL Companies, is inconsistent with the language of the corresponding Requirement R2.⁹ Requirement R2 does not allow for any deviation from the voltage or Reactive Power schedule. Requirement R2 states:

Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule^[FN3] (within applicable Facility Ratings^[FN4]) as directed by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

⁸ See Section 215(d)(2) of the Federal Power Act.

⁹ **R2.** Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule^[FN3] (within applicable Facility Ratings^[FN4]) as directed by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2.1. When a generator’s automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

[FN3: The voltage or Reactive Power schedule is a target value communicated by the Transmission Operator to the Generator Operator establishing a tolerance band within which the target value is to be maintained during a specified period.]

[FN4: When a Generator is operating in manual control, Reactive Power capability may change based on stability considerations and this may lead to a change in the associated Facility Ratings.]

The Commission has noted that a VSL is “a *post-violation* measurement of the degree (‘Lower,’ ‘Moderate,’ ‘High,’ or ‘Severe’) to which a requirement was violated.”¹⁰ For this reason, in order to effectuate a 30 minute window, the language of Requirement R2 would have to be modified. In accordance with Commission precedent, VSLs must be consistent with the corresponding Requirement,¹¹ and consistency with Requirement R2 requires that the “floor” must be at zero. Therefore, the proposal put forth by the PPL Companies cannot be implemented as requested and would require a revision to Requirement R2.

3. The Proposed Modification is Inconsistent With Reliability Principles and Should be Rejected.

NERC contends that the proposed modification is inconsistent with reliability principles and respectfully submits that it should be rejected by the Commission. The proposed modification would allow for deviations in system voltage for up to 30 minutes to allow for time to correct an excursion. PPL Companies states that “is a reasonable amount of time that allows for plant equipment and/or plant operating personnel to adequately assess the situation (*i.e.*, system conditions, equipment conditions, etc.) and perform the necessary actions required to correct the voltage.”¹²

NERC submits that a deviation from a voltage or Reactive Power schedule is inconsistent with reliability principles because a deviation of even up to a few minutes can negatively impact reliability. Significant voltage deviations for extended periods of time may lead to voltage collapse and can increase the potential for wide-area impacts to the reliability of the Bulk-Power System. For this reason, NERC respectfully submits that the Commission should reject the proposed modification.

¹⁰ *North American Electric Reliability Corp.*, 123 FERC ¶ 61,284 at P 3 (2008)(emphasis added).

¹¹ *See infra.* at n. 1.

¹² *See* Motion to Intervene and Comments of the PPL Companies at 4.

III. CONCLUSION

For the reasons stated above, NERC respectfully requests that the Commission accept these comments for consideration.

Respectfully submitted,

/s/ Stacey Tyrewala

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Stacey Tyrewala
Attorney
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

*Counsel for North American Electric Reliability
Corporation*

Dated: January 23, 2013

January 31, 2013

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

**Re: Analysis of NERC Standard Process Results, Fourth Quarter 2012
Docket Nos. RR06-1-000, RR09-7-000**

Dear Ms. Bose:

The North American Electric Reliability Corporation (“NERC”) hereby submits its Analysis of NERC Standards Process Results for the Second Quarter 2012 (“Ballot Results Analysis”). This filing is submitted in response to the Federal Energy Regulatory Commission’s (“FERC” or the “Commission”) January 18, 2007 Order¹ requiring NERC to closely monitor and report the voting results for NERC Reliability Standards each quarter for three years and the Commission’s subsequent order issued on September 16, 2010, whereby the Commission renewed and expanded on its directive for an additional three years.²

The Ballot Results Analysis is attached hereto and addresses ballot results during the October 1, 2012 through December 31, 2012 timeframe, and includes NERC’s analysis of the voting results, including trends and patterns of stakeholder approval of NERC Reliability Standards. NERC requests that the Commission accept this compliance filing in accordance with the directive in the September 16, 2010 Order to submit quarterly reports for an additional three years from the date of the order.

Respectfully submitted,

/s/ Stacey Tyrewala

Stacey Tyrewala

*Attorney for North American Electric Reliability
Corporation*

cc: Official service list in Docket No. RR06-1-000; RR09-7-000

¹ Order on Compliance Filing, 118 FERC ¶ 61,030 at P 18 (2007).

² Order on the Electric Reliability Organization’s Three-Year Performance Assessment, 132 FERC ¶ 61,217 at P 85 (2010).

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Analysis of NERC Standards Process Results

Fourth Quarter 2012

January 31, 2013

RELIABILITY | ACCOUNTABILITY



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

Table of Contents

Introduction	1
Background: NERC’s Revised Processes for Developing Standards	1
This Report	1
Analysis of Q4 2012 Standards Ballot Results.....	2
Q4 2012 Ballots and Comparison to Baseline Data	9
Conclusion	13
Appendix A, Types of Standards Projects	14

Introduction

Background: NERC's Processes for Developing Standards

NERC develops Reliability Standards in accordance with Section 300 of its Rules of Procedure and the NERC *Standard Processes Manual*, which is included as Appendix 3A to the NERC Rules of Procedure.¹ The current *Standard Processes Manual* ("SPM") was approved by the Federal Energy Regulatory Commission ("FERC" or the "Commission") in September 2010² and amended in August 2011.³ NERC is in the midst of changes to its standard development processes, and is using the experience gained through implementing the SPM and earlier versions of NERC's standard development process to foster the success of future changes.

Many of the standards projects currently in development either were initiated under the predecessor processes and continued under the SPM, or were initiated under the SPM but have not yet been completed.

This Report

This report is responsive to directives from FERC directing NERC to monitor, analyze, and report on the results of its standards development process.⁴

At the end of each calendar quarter, NERC updates this report by incorporating results from the most recent calendar quarter, to monitor and report progress on improvements to various aspects of the standards development process. The first section of this report provides an overview and analysis of ballots conducted during the fourth quarter of 2012. The second section compares timelines for the projects balloted in the fourth quarter of 2012 against baselines provided in the report filed on January 31, 2011, based on the time required to complete each phase of standards development. The comparison to the historical baselines is responsive to the Commission's directive to analyze the time required to complete each phase of the standards development process. NERC staff and the Standards Committee use this analysis to monitor successes and to identify opportunities for improvements.

¹ NERC's Rules of Procedure are available at: <http://www.nerc.com/page.php?cid=1|8|169>.

² *Order Approving Petition and Directing Compliance Filing*, 132 FERC ¶ 61,200 (2010).

³ *Letter Order Approving Standard Processes Compliance Filing* (August 25, 2011).

⁴ See *Order on Compliance Filing*, 118 FERC ¶ 61,030 (2007). See also, *Order on the Electric Reliability Organization's Three-Year Performance Assessment*, 132 FERC ¶ 61,217 at P 85 (September 16, 2010) ("Three-Year Assessment Order"). Specifically, the Three-Year Assessment Order directed NERC to analyze:

- (i) the time required to complete projects (excluding urgent action projects);
- (ii) the time required to complete projects initiated in response to NERC's urgent action progress (including whether or not a permanent fix was implemented within the sunset period); and
- (iii) the time required to complete projects in response to Commission directives. The analysis should include data on the time required for each stage of the process. For example, the analysis should document the time required to move a proposed Reliability Standard from a Standards Authorization Request to the NERC Board, and then to the Commission.

Analysis of Q4 2012 Standards Ballot Results

From October 1, 2012 through December 31, 2012, NERC conducted ballots of 22 standards, three interpretations, 19 new or revised definitions, and one project that proposed retirements of requirements in 22 standards. NERC also conducted 10 non-binding polls of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), along with one non-binding poll for a set of revisions to outstanding VRFs and VSLs in 29 standards.

Seven projects (encompassing 17 standards, one interpretation, and revisions to outstanding VRFs and VSLs in 29 standards) include standards that have completed the technical input and stakeholder consensus phase in the fourth quarter of 2012.

Of those, 11 standards were adopted by the Board in November 2012 and are pending regulatory filing: PRC-005-2 (developed under Project 2007-17) and 10 CIP Version 5 Standards (CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1, developed under Project 2008-06). Another standard, EOP-004-2 (developed under Project 2009-01), was also adopted by the Board in November 2012 and was filed with FERC in December 2012.

An interpretation to BAL-002-0 R4 and R5 (developed under Project 2009-19) was also approved by the Board in November 2012 and is pending regulatory filing. The revisions to outstanding VRFs and VSLs were approved by the Board in December 2012 and will also be filed with applicable regulatory authorities in 2013.

Five standards balloted during the fourth quarter 2012 have completed recirculation ballot and are pending Board approval: MOD-025-2, MOD-026-1, MOD-027-1, and PRC-019-1 (developed under Project 2007-09), and BAL-003-1 (developed under Project 2007-12).

Seven projects balloted during the fourth quarter of 2012 (encompassing five standards, two interpretations, and the 22-standard Paragraph 81 requirement retirement project) were ongoing at the end of the quarter.

Table 1 summarizes these ballot events. A complete record for each project is available on NERC's website on the Ballot Results webpage.⁵

⁵ The Ballot Results webpage is available at: <https://standards.nerc.net/Ballots.aspx>.

Table 1

Project Type⁶	Project Number & Name	Q4 Ballot Events	Status
New	2007-02 Operating Personnel Communications Protocols	Successive ballot and non-binding poll of VRFs and VSLs for one standard (COM-003-1)	Ongoing
New	2007-06 System Protection Coordination	Successive ballot and non-binding poll of VRFs and VSLs for one standard (PRC-027-1)	Ongoing
Revision	2007-09 Generator Verification	Successive ballot of one standard (PRC-024-1); successive and recirculation ballots of four additional standards (MOD-025-2, MOD-026-1, MOD-027-1, PRC-019-1); non-binding polls of VRFs and VSLs for all five standards	Four standards will be presented to the Board in February 2013; development of PRC-024-1 is ongoing
Revision	2007-12 Frequency Response	Successive and recirculation ballot of one standard (BAL-003-1); one non-binding poll of VRFs and VSLs	Will be presented to the Board in February 2013
Revision	2007-17 Protection System Maintenance & Testing	Recirculation ballot of one standard (PRC-005-2)	Adopted by NERC Board in November 2012; pending regulatory filing
Revision	2008-06 Cyber Security	Successive and	Adopted by NERC Board in

⁶ Appendix A to this report provides a brief description of each type of standards project.

Project Type ⁶	Project Number & Name	Q4 Ballot Events	Status
	Order 706 (CIP Version 5)	recirculation ballots of ten standards (CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1) and 19 new or revised definitions; one non-binding poll of VRFs and VSLs	November 2012; pending regulatory filing
Revision	2009-01 Disturbance and Sabotage Reporting	Recirculation ballot and non-binding poll of VRFs and VSLs for one standard (EOP-004-2)	Adopted by NERC Board in November 2012; filed with FERC in December 2012
Revision	2010-11 TPL footnote b	Initial ballot of two standards (TPL-001-2a and TPL-002-1c) ⁷	Ongoing
Revision	2013-02 Paragraph 81	Initial ballot of retirements to requirements in 22 standards	Ongoing
Revision	Revisions to Outstanding VRFs and VSLs	Non-binding poll of revisions to a set of outstanding VRFs and VSLs in 29 standards	Adopted by NERC Board in December 2012; pending regulatory filing
Interpretation	2009-19 Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group	Recirculation ballot of one interpretation	Adopted by NERC Board in November 2012; pending regulatory filing
Interpretation	2012-INT-02 Interpretation of TPL-003-0a and TPL-004-0 for	Initial ballot of one interpretation	Ongoing

⁷ When work was initiated to revise the footnote in response to the Commission's remand order, these standards were numbered as TPL-001-2a and TPL-002-1c. This numbering is inconsistent with NERC's Standards Numbering Convention, posted at http://www.nerc.com/files/NERC_Standards_Numbering_Convention_2009Sept14.pdf. The numbering was corrected prior to the recirculation ballot to conform to the Numbering Convention. The correct numbers are TPL-001-3 and TPL-002-2b.

Project Type ⁶	Project Number & Name	Q4 Ballot Events	Status
	SPCS		
Interpretation	2012-INT-05 Interpretation of CIP-002-3 for OGE	Initial ballot of one interpretation	Ongoing

Additional detail for the 13 projects that had standards balloted in the fourth quarter of 2012 is provided below. With the exception of Paragraph 81 and Revisions to Outstanding VRFs and VSLs, for each project involving multiple standards, separate ballots were conducted for each standard. NERC has adopted the practice of balloting each standard individually because this approach provides drafting teams with more specific information about which standards require additional development work to reach consensus.

Ballots were conducted in the fourth quarter of 2012 for the following projects:

- Project 2007-02 Operating Personnel Communications Protocols:** This project proposes to remove Requirement R4 from COM-001-1 and Requirement R2 from COM-002-3 for inclusion in a new standard, COM-003-1, to address part of Blackout Recommendation No. 26 and issues in FERC Order 693. A successive ballot of COM-003-1 achieved a high quorum of over 76 percent and weighted segment approval of over 53 percent. The associated non-binding poll for the VRFs and VSLs achieved a quorum of 77 percent and an approval rating of 58 percent. Work to revise the standard in response to stakeholder comments is ongoing.
- Project 2007-06 System Protection Coordination:** PRC-027-1 is a results-based standard to coordinate Protection Systems utilized to protect Interconnected Elements, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the System performance specified within requirements established in other approved NERC Reliability Standards. This standard incorporates and enhances the coordination aspects of Requirements R3 and R4 from PRC-001-1 (now R2 and R3 of PRC-001-2). A successive ballot of PRC-027-1 received a high quorum of over 76 percent and weighted segment of approval of 33 percent. The associated non-binding poll for the VRFs and VSLs achieved a quorum of 76 percent and an approval rating of 35 percent. Work to revise the standard in response to stakeholder comments and successive ballot is ongoing.
- Project 2007-09 Generator Verification:** Project 2007-09 incorporates revisions to two existing standards (MOD-024-1 and MOD-025-1 were incorporated into the proposed MOD-025-2), and the development of four new standards (MOD-026-1, MOD-027-1, PRC-019-1, and PRC-024-1), in order to (1) ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and (2) ensure that generator models accurately reflect the generator's capabilities and operating characteristics. All five standards being revised or developed

were posted for a successive ballot that ended on October 31, 2012. In that ballot, all standards received a high quorum of at least 75 percent. MOD-025-2 received an approval rating of 68 percent; MOD-026-1 received an approval rating of 77 percent; MOD-027-1 received an approval rating of 72 percent; PRC-019-1 received an approval rating of 71 percent; and PRC-024-1 received an approval rating of 57 percent. In an associated non-binding poll for the VRFs and VSLs, all of the polls achieved a quorum of at least 75 percent. The VRFs and VSLs for MOD-025-2 received an approval rating of 64 percent; the VRFs and VSLs for MOD-026-1 received an approval rating of 77 percent; the VRFs and VSLs for MOD-027-1 received an approval rating of 69 percent; the VRFs and VSLs for PRC-019-1 received an approval rating of 64 percent; and the VRFs and VSLs for PRC-024-1 received an approval rating of 52 percent. Additional work on PRC-024-1 is required, and the drafting team has posted the standard for another successive ballot that will end in 2013. The other four standards proceeded to recirculation ballot. In that ballot, MOD-026-1 received a high quorum of 79 percent; PRC-019-1, MOD-027-1, and MOD-025-2 all received a high quorum of at least 85 percent. MOD-025-2 received an approval rating of 73 percent; MOD-026-1 received an approval rating of 79 percent; MOD-027-1 received an approval rating of 74 percent; PRC-019-1 received an approval rating of 73 percent. All of the standards except PRC-024-1 will be presented to the Board for adoption in February 2013. PRC-024-1 is still under development.

- **Project 2007-12 Frequency Response:** The proposed BAL-003-1 would set a minimum Frequency Response obligation for each Balancing Authority, provide a uniform calculation of Frequency Response and Frequency Bias Settings that transition to values closer to natural Frequency Response, and encourage coordinated Automatic Generation Control operation. A successive ballot concluded on November 6, 2012, achieving a high quorum of over 80 percent and a weighted segment approval of over 76 percent. The associated non-binding poll for the VRFs and VSLs achieved a quorum of 76 percent and an approval rating of 76 percent. The recirculation ballot concluded on December 21, 2012 with a high quorum of 86 percent and weighted segment approval of over 76 percent. This standard will be presented to the Board for adoption.
- **Project 2007-17 Protection System Maintenance and Testing:** This project merges requirements from four protection system maintenance standards into a single standard, PRC-005-2. A recirculation ballot of PRC-005-2 achieved a high quorum of 81 percent and ballot approval of approximately 80 percent. The standard was adopted by the Board in November 2012, and is pending regulatory filing.
- **Project 2008-06 Cyber Security Order 706:** In the development of the NERC Version 5 CIP Reliability Standards, the Project 2008-06 Cyber Security Order 706 standard drafting team was charged with addressing all remaining standards-related issues from [FERC Order No. 706](#). The standards provide a cyber security framework for the categorization and protection of Bulk Electric System (BES) cyber systems to support the reliable operation of the BES. In the fourth quarter of 2012, the ten CIP standards (CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1), an associated implementation plan, and 19 new or revised NERC Glossary Terms completed both a successive ballot and a recirculation ballot. The successive ballot, which ended on October 10, 2012, achieved a quorum of about 80 percent for all documents, and at least a 74 percent approval for all documents. The standards and associated documents were approved with high quorum

of about 85 percent and at least a 78 percent approval rating in recirculation ballots that ended on November 5, 2012. Nine of the 12 recirculation ballots passed with over 90 percent approval. A non-binding poll for the standards' VRFs and VSLs was also conducted alongside the recirculation ballot, and those assignments achieved a quorum of 75 percent and about 84 percent approval. The standards and all associated documents were adopted by the Board in November 2012 and are pending regulatory filing.

- **Project 2009-19 Interpretation of BAL-002-0 Requirements R4 and R5:** This interpretation project clarifies the obligations of Balancing Authorities and Reserve Sharing Groups under certain conditions. An initial ballot of the interpretation was conducted in early 2010, but work on the interpretation was curtailed when the Standards Committee supported NERC staff's assessment that an interpretation could not be drafted that conformed to the guidance to interpretation drafting teams that an interpretation rely strictly on the requirements of the standard. In May 2012, the Board provided additional guidance for interpretations, indicating that interpretation drafting teams need not be limited to the language of the requirements in the standard in preparing an interpretation. After receiving this guidance, the project was reactivated. A successive ballot concluded on September 4, 2012. The interpretation achieved a high quorum of over 79 percent and a weighted segment approval of over 87 percent. Work to revise the interpretation in response to stakeholder comments was completed and a recirculation ballot was initiated on September 28, 2012, achieving a high quorum of over 85 percent and a weighted segment approval of over 90 percent. This interpretation was adopted by the Board in November 2012 and is pending regulatory filing.
- **Project 2009-01 Disturbance and Sabotage Reporting:** This project consolidates requirements from CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into a single standard, EOP-004-2. A recirculation ballot of the standard achieved a high quorum of over 85 percent and weighted segment approval of over 71 percent. The associated non-binding poll for the VRFs and VSLs achieved a quorum of 79 percent and an approval rating of 71 percent. The standard was adopted by the Board in November 2012, filed with FERC in December 2012, and is pending regulatory approval.
- **Project 2010-11 TPL Table 1 Order:** This project addresses FERC Order RM06-16-009, which requires the Electric Reliability Organization (ERO) to clarify TPL-002-0, Table 1 — footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The Standard Authorization Request (SAR) provided a revision to TPL Table 1 footnote 'b' to provide clarity to industry with regard to the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. The referenced table appears in TPL-001, TPL-002, TPL-003, and TPL-004, so while the FERC Order was for TPL-002, the change is reflected in all four standards. The initial ballot for the revisions to a single footnote that were incorporated into two standards (TPL-002-1c— System Performance Following Loss of a Single BES Element as footnote 'b', and TPL-001-2a — Transmission System Planning Performance Requirements as footnote 12) achieved a high quorum of

over 80 percent; the weighted segment approval was over 56 percent. Work to revise the standard in response to stakeholder comments is ongoing.

- **Project 2012-INT-02 Interpretation of TPL-003 and TPL-004:** This interpretation request was submitted by SPCS to address FERC's concern about the study of single point of failure in protection systems, documented in Order No. 754. An initial ballot for the interpretation of TPL-003-0a – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) and TPL-004-0 – System Performance Following Extreme Events Results in the Loss of Two or More Bulk Electric System Elements (Category D) achieved a high quorum of over 84 percent and weighted segment approval of over 72 percent. Work to revise the interpretation in response to stakeholder comments is ongoing.
- **Project 2012-INT-05 Interpretation of CIP-002-3:** OGE requested interpretation of CIP-002-3 for clarification regarding the applicability of CIP-002-3 to Advanced Meter Infrastructure systems. An initial ballot of the interpretation achieved a high quorum of over 84 percent and weighted segment approval of over 95 percent. Work to revise the interpretation in response to stakeholder comments is ongoing.
- **Project 2013-02 Paragraph 81:** This project is responsive to paragraph 81 of FERC's March 15, 2012 Order issued on NERC's Find, Fix and Track process. The purpose of the project is to retire or modify FERC-approved Reliability Standard requirements that, as FERC noted, "... provide little protection to the reliable operations of the BES...", are redundant or unnecessary, or whose retirement or modification could increase the efficiency of the ERO's compliance programs. The project identifies Reliability Standard requirements that clearly meet the criteria set forth in the SAR and do not require extensive technical research. Future standards projects will incorporate work on Reliability Standard requirements that need additional technical research before retirement or modification. This project achieved a high quorum of over 75 percent; the weighted segment approval was over 96 percent. At the end of the fourth quarter 2012, work to revise the list of requirements being proposed for retirement in response to stakeholder comments was ongoing.
- **Revisions to Outstanding VRFs and VSLs:** Initiated by NERC staff and completed in coordination with FERC staff and stakeholders, this project addresses a set of VRF and VSL assignments in 29 standards that FERC identified as needing possible revision or further justification. In general, the VRFs and VSLs require revision in order to reflect the NERC and FERC VRF and VSL guidelines finalized between 2007 and 2009. The revised assignments were posted for a single 45-day comment period and non-binding poll, and they received 73 percent approval in a poll with a high quorum of just over 78 percent. The revisions were approved by the Board in December 2012 and are pending regulatory filing.

Q4 2012 Ballots and Comparison to Baseline Data

In the version of this report filed on January 31, 2011, NERC provided baselines for each phase of development for standards projects. These baselines were established by grouping all NERC standards projects from 2006 through 2010 into four categories (new standards, revisions to existing standards, expedited projects, and interpretations) and then averaging the times for each phase of development within each group. Averages were developed by project without consideration to the number of standards associated with each project.

In this section of the report, NERC compares the projects balloted each quarter against these baselines to identify trends in the time required for various phases of standards development. As noted above, during the fourth quarter of 2012, NERC conducted ballots of 22 standards, three interpretations, 19 new or revised definitions, and one project that proposed retirements of requirements in 22 standards. Only standards and interpretations balloted during the fourth quarter of 2012 are included in the chart.

Chart 1 compares the development phases for each of the standards revision projects, including Project 2013-02, which proposed retirements to requirements in 22 standards.

Q4 2012 Projects to Revise Existing Standards

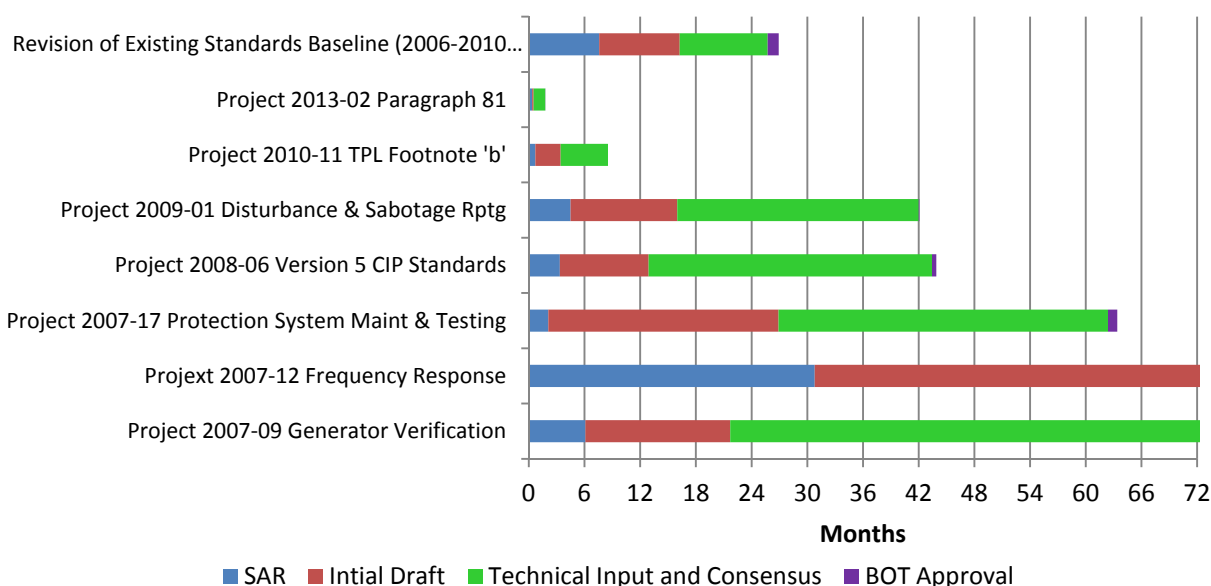


Chart 1

Chart 2 compares the development phases of the two projects to develop new standards that were balloted in the fourth quarter against the baseline for all such projects balloted between 2006 and 2010.

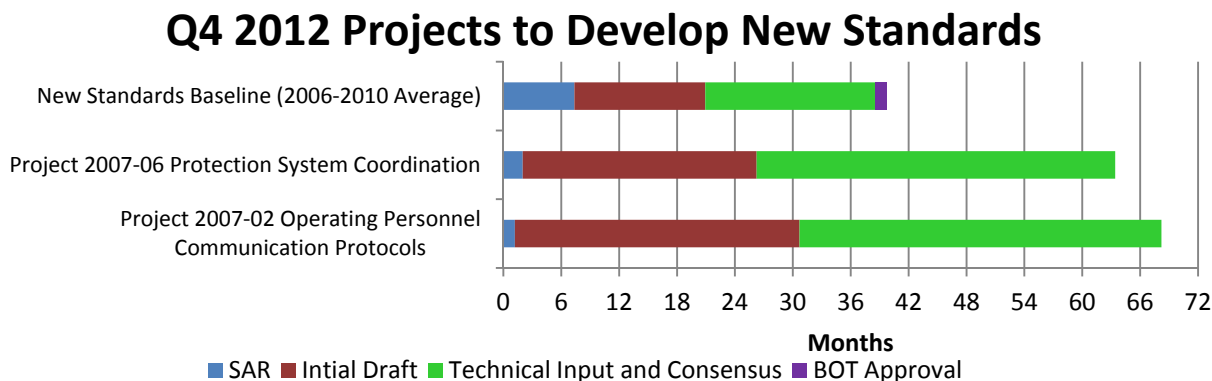


Chart 2

Chart 3 compares the development phases of the three interpretation project balloted in the fourth quarter to the baseline of all interpretations balloted between 2006 and 2010.

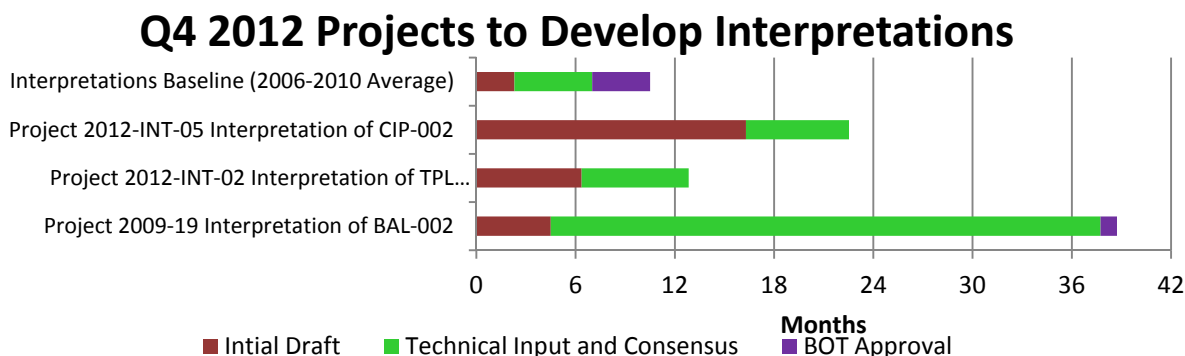


Chart 3

SAR Development Phase. For all but one of the standards projects balloted in the fourth quarter of 2012, the SAR was finalized quickly after being posted for industry review. From 2006 to 2010, SAR development times averaged eight months for a project to revise one or more existing standards, and slightly less for projects to develop one or more new standards. Eight of the nine projects that were balloted in the fourth quarter had SAR development phases of about six months or less. Only one project, Project 2007-12 Frequency Response, had a SAR development phase longer than the baseline. This general trend toward the shortening of the SAR development period is expected to continue as consensus on the scope of a project, as well as much of the technical analysis, is expected to be completed prior to the initiation of work on the project.

Initial Draft Phase. The 2006-2010 baseline for the initial draft input phase was just under nine months for revision projects, just under 14 months for new standard projects, and just over two months for interpretations. One of the seven revision projects, Project 2010-11 TPL Footnote b, took less than three months to develop the initial draft, and Project 2013-02 Paragraph 81 skipped the initial draft phase and move straight from the informal consensus-building phase into the technical input and consensus phase. All other projects from the fourth quarter of 2012 took longer than the baseline to complete an initial draft. Many of these projects included more than one standard and took only slightly longer than the baseline to complete the technical input phase. For instance, Project 2008-06 revised or developed 10 CIP standards and only took 9.5 months to develop the initial draft, which indicates that NERC is implementing the tools to more efficiently develop initial drafts, even for complicated, large projects. Additionally, changes proposed to drafting team makeup for 2013 and beyond should make the development of an initial draft more efficient; drafting teams will be smaller and more agile and may be in a better position to develop drafts quickly with the informal participation of other industry subject matter experts.

Technical Input Phase. Drafting teams seek technical input from the industry through the formal and informal posting periods. Between each posting, the drafting team reviews the feedback received from stakeholders and makes revisions to the standard or standards. For a formal posting, drafting teams are also required to respond to each stakeholder comment. Thus, the technical input phase includes periods of time when standards and associated documents are posted for industry review – typically either for 30 or 45 days – alternating with periods of time during which the drafting team is reviewing the input provided, revising the standards and associated documents, and preparing both individual and summary responses to the comments received. The technical input phase is essentially a highly-organized dialogue between the drafting team and other industry stakeholders.

Seven projects, 2007-09 Generator Verification (with the exception of PRC-024-1), 2007-12 Frequency Response, 2007-17 Protection System Maintenance & Testing, 2008-06 Cyber Security Order 706 (CIP Version 5), 2009-01 Disturbance and Sabotage Reporting, Revisions to Outstanding VRFs and VSLs, and 2009-19 Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group, completed their technical input phase in the fourth quarter of 2012. The standards in those projects are either awaiting Board adoption or pending regulatory filing. For the remaining seven projects, the technical input phase will continue.

The 2006-2010 baseline for the technical input phase was nine-and-a-half months for revision projects, just under 18 months for new standard projects, and just under five months for interpretations. The technical input phases for Project 2013-02 Paragraph 81 and 2010-11 TPL Footnote b are poised to take less time than that to complete the input process, but the technical input phase has taken longer for all other projects.

In 2013 and beyond, changes proposed to the Standard Processes Manual will reduce some of the burden on drafting teams during the technical input phase without eliminating the requirement to review and consider each industry comment. That change, combined with the increased focus on informal consensus building in early stages of the development process, will help reduce the time spent during the formal technical input process.

Board of Trustee Adoption. The baseline period of time between ballot pool approval of a standard and Board adoption of the standard is about five weeks. The period of time between ballot pool approval of a standard and Board adoption can vary based on the Board's fixed schedule of face-to-face meetings, but in the fourth quarter of 2012 all standards or interpretations projects that completed ballot pool approval were adopted by the Board in one month or less – a shorter time period than the baseline.

Filing with Regulatory Authorities. During the fourth quarter of 2012, two filings to FERC were made for standards projects that required Board adoption.

- On November 21, 2012, a Petition for Approval of Proposed Reliability Standard VAR-002-2b Generator Operation for Maintaining Network Voltage Schedules was submitted in Docket No. RD13-2-000.
- On December 31, 2012, a Petition for Approval of Proposed Reliability Standard EOP-004-2 Event Reporting was submitted in Docket No. RD13-3-000.

Conclusion

In the fourth quarter of 2012, NERC has demonstrated its ability to conduct its standards process more efficiently in projects like Project 2013-02 Paragraph 81, Project 2008-06 Version 5 CIP Standards, and Project 2010-11 TPL Footnote b. These projects illustrate the importance of informal consensus building early in the development process, expert project management, and the collaboration of the industry in providing clear, concise, and actionable feedback. Along with continuing to utilize these proven tools for success in 2013 and beyond, NERC has introduced a number of other efforts to modify its standards development process to ensure a clear focus on the efficient production of technically sound Reliability Standards.

NERC has made significant strides toward implementing the Standard Process Input Group's recommendations for improving the standards development process. In large part, that progress is evident in the proposed changes to the Standard Processes Manual (SPM), which is slated for recirculation ballot in early 2013. Changes to the SPM will promote informal consensus building and collaboration between standards and compliance staff; streamline the commenting and balloting process; reduce the requirement for periodic review; and incorporate a waiver provision to allow for modifications to the standards development process for good cause.

These changes will be supported by substantial organizational changes in the standards department that were implemented in the third quarter of 2012, the Board adoption of the Reliability Standards Development Plan 2013-2015 (which represents a bold revision of NERC's approach to managing the standards development workload), and enhanced guiding documents for the Standards Committee. Together, these efforts will enable NERC to improve the efficiency of its standards development process and transform the ERO's body of standards into a world-class body of results-based standards.

Appendix A

Types of Standards Projects

For the purpose of analyzing results of its standards processes, NERC has identified four broad categories of standards projects.

The first category of projects is **Revisions to Existing Standards**. Revisions to existing standards are a significant and an ongoing part of NERC's standards development work, as NERC and industry work to address regulatory directives from FERC, modify standards to address changing technologies and operating conditions, and review standards in compliance with the five-year interval required to maintain ANSI accreditation. Between 2006 and 2010, the average time to complete revisions to existing standards was 30 months.

The second category is **New Standards**. There have been, and will continue to be, occasions where an entirely new standard or group of standards may be needed to address bulk power system reliability. The data collected from 2006 through 2010 show that these projects take longer, on average, than projects to revise existing standards. Between 2006 and 2010, the average time to complete projects to draft new standards was 42 months.

The third category is **Urgent Action/Expedited Projects**.⁸ Urgent Action or Expedited Projects are shortened by reducing the time for certain process steps, or by allowing steps that would normally proceed serially to be conducted in parallel. By definition, these projects are expected to have a shorter development time, on average, than most standards projects. On average, the development time for Urgent Action and Expedited Projects from 2006 through 2010 was a little more than 7 months.

The final category is **Interpretations**. Entities that must comply with a reliability standard have the right to request a formal interpretation of a requirement included in a standard. Interpretation projects generally are narrower in scope than other standards projects, but like standards, interpretations are drafted by a drafting team and posted for industry review and ballot. From 2006 to 2010, NERC received a number of requests for interpretation that were absorbed into other projects because drafting teams could not prepare the interpretations without expanding the requirements of the approved standard. For those interpretation requests that were processed, the average time to complete interpretations and file them with regulatory authorities was about 10 months.

⁸ Prior to September 2010, the NERC *Reliability Standards Development Procedure* incorporated a process used for developing a standard more quickly than the normal standard development process, which was referred to as the Urgent Action Process. FERC's approval of the *Standard Processes Manual* in September 2010 replaced the Urgent Action process with the Expedited Standards Development Process.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**Revisions to Reliability Standard for
Transmission Vegetation Management**)
)

Docket No. RM12-4-000

**MOTION FOR LEAVE TO FILE REPLY COMMENTS AND
REPLY COMMENTS OF THE NORTH AMERICAN
ELECTRIC RELIABILITY CORPORATION
REGARDING COMMENTS RECEIVED ON NOTICE OF
PROPOSED RULEMAKING**

Pursuant to Rule 212 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (“Commission”), 18 C.F.R. § 385.212 (2012), and in response to comments submitted to the Commission regarding the Notice of Proposed Rulemaking issued in this proceeding on October 18, 2012,¹ the North American Electric Reliability Corporation (“NERC”) respectfully submits this Motion for Leave to File Reply Comments and Reply Comments. NERC provides these reply comments as the Commission-certified² electric reliability organization (“ERO”) responsible for the development and enforcement of mandatory Reliability Standards, including proposed FAC-003-2.

On December 21, 2012, NERC submitted comments addressing several sections of the Commission’s NOPR. A number of other entities also filed comments. NERC respectfully requests that the Commission consider NERC’s reply comments clarifying and responding to certain issues raised by commenters. The Commission should accept these reply comments because they provide information to assist the Commission in this proceeding.

¹ *Revisions to Reliability Standard for Transmission Vegetation Management*, Notice of Proposed Rulemaking, 141 FERC ¶ 61,046 (2012).

² *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).

I. Notices and Communications

Notices and communications with respect to this filing may be addressed to:³

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile

Charles A. Berardesco*
Senior Vice President and General Counsel
Holly A. Hawkins*
Assistant General Counsel
William H. Edwards*
Attorney
Nina H. Jenkins-Johnston*
Attorney
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
william.edwards@nerc.net
nina.johnston@nerc.net

II. Comments and NERC Responses

A. The Proposed Definition of Right-of-Way Should Be Approved as Filed in NERC's Petition

A number of commenters raise concerns regarding the proposed definition of Right-of-Way. The proposed definition of Right-of-Way reads:

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The [Right-of-Way] width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.⁴

³ Persons to be included on the Commission's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

⁴ See NERC Dec. 21, 2011 Petition at 2.

NERC responds here to comments submitted by the ITC Companies (“ITC”) in response to the Commission’s NOPR.⁵ ITC argues that the definition of Right-of-Way should be revised to clarify the phrase “needed to operate the line.” ITC also asks the Commission to provide an additional method for a utility to provide necessary documentation to establish the Right-of-Way other than those identified in the proposed definition. ITC states that the documentation enumerated in the proposed definition may be incomplete, unavailable, or problematic for utilities to implement. ITC further proposes that the Commission modify the proposed Right-of-Way definition to allow Transmission Owners to establish an appropriate standard for establishing the Right-of-Way width based on current industry standards. ITC also proposes a specific modification to the definition that provides additional clarity to the definition of Right-of-Way and provides certainty as to the types of records that support a utility’s determination of a Right-of-Way.

NERC’s Response

The definition of Right-of-Way should be approved as filed in NERC’s Petition, and the Commission should reject ITC’s request to make specific changes to the proposed definition of Right-of-Way in this proceeding. Any changes to the proposed definition, if necessary and ordered by the Commission under section 215(d)(5) of the Federal Power Act,⁶ should be made through the Reliability Standards development process.

NERC draws the Commission’s attention to an industry comment submitted during the development of the proposed standard and NERC’s response, which demonstrates the standard drafting team fielded a similar concern. The comment and response are both included in

⁵ See ITC Dec. 26, 2012 Comments.

⁶ 16 U.S.C. § 824o(d)(5) (2006).

NERC's Petition in this proceeding.⁷ During the fifth posting of the proposed standard, Hydro One commented:

The revised definition of [Right-of-Way] is unclear in regards to the application of standards and/or historic records as a means of determining [Right-of-Way] width; is it necessary for a [Transmission Owner] to select one method to apply in all cases, or can each span be treated in the manner deemed most appropriate by the [Transmission Owner]? Additionally "blowout Standard" has not been defined in the document or in the technical paper, and therefore it is not clear exactly how this method would be applied, and subsequently defended under scrutiny.⁸

In response, the standard drafting team:

- (i) determined that the proposed definition would be sufficient to establish a Right-of-Way because the definition includes a series of options that give the Transmission Owner latitude in establishing Right-of-Way width;
- (ii) explained that the definition of Right-of-Way does not require selecting a single method; and
- (iii) explained that the term "blowout standard" is not a defined term, and is intended to represent the conductor "blow out" design criteria used when the line was constructed. The team explained that inclusion of this undefined phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the Right-of-Way width.

NERC agrees with the standard drafting team that the definition includes the necessary latitude for a Transmission Owner to determine a Right-of-Way using the documentation identified.

B. NERC Has the Authority to Enforce Reporting Obligations Under Its Rules of Procedure

The City of Santa Clara, California (d/b/a Silicon Valley Power ("SVP")) submitted comments urging that the quarterly reporting obligation under proposed FAC-003-2 should be

⁷ See NERC Petition, Ex. E (Consideration of Comments on Draft 5 of FAC-003-2) at 10.

⁸ *Id.*

treated as a section 1600⁹ request for data or information because NERC seeks to move the reporting obligation from the “Requirement” section to the “Additional Compliance Information” section of the proposed standard.¹⁰ Like a section 1600 request for data or information, SVP contends that NERC’s only recourse for noncompliance with the reporting obligation is to request that the Commission exercise its enforcement authority to require the Reporting Entity to comply and for the Commission to take other appropriate enforcement action. SVP insists that like a request for data or information under section 1600, a quarterly reporting obligation that is under the “Additional Compliance Information” section is broad and not directly relevant to monitor a registered entity’s compliance with a particular standard Requirement.¹¹ SVP maintains that section 3.6 of Appendix 4C only assesses a registered entity’s compliance with a Requirement and not with other provisions of a standard such as the “Additional Compliance Information” section.¹²

NERC Response

In NERC’s Petition, NERC proposes to move a quarterly reporting obligation regarding sustained transmission outages caused by vegetation out of the Requirements section of the proposed standard to the “Additional Compliance Information” section of the Reliability Standard. Enforcing the quarterly reporting obligation found in the “Additional Compliance Information” section of the proposed FAC-003-2 Reliability Standard is consistent with the NERC Rules of Procedure¹³ and the regulations corresponding to section 215 of the Federal

⁹ In accordance with section 1600 of the NERC Rules of Procedure, NERC may request data or information that is necessary to meet its obligations under section 215 of the FPA, as authorized by section 39.2(d) of the Commission’s regulations.

¹⁰ SVP Dec. 21, 2012 Comments at 8.

¹¹ *Id.* at 8.

¹² *Id.* at 7.

¹³ References to the Rules of Procedure are to the version effective on December 20, 2012. *See* Order Conditionally Approving Revisions to North American Electric Reliability Corporation Rules of Procedure, 141 FERC ¶ 61,241 (2012) (“ROP Order”).

Power Act. The relevant enforcement mechanisms are Commission-approved and exist in the NERC Rules of Procedure under section 400 and Appendix 4C (Uniform Compliance Monitoring and Enforcement Program).

Section 401.3 of the NERC Rules of Procedure provides that NERC and the Regional Entities can require “[a]ll Bulk Power System owners, operators and users” to provide “such information as is necessary to monitor compliance with the reliability standards.” Appendix 4C to the NERC Rules of Procedure states that the Compliance Enforcement Authority will “*monitor, assess, and enforce* compliance with Reliability Standards using the compliance monitoring processes. . .to collect information in order to make assessments of compliance.”¹⁴ The quarterly reporting obligation in the proposed standard is squarely part of NERC’s compliance, monitoring, and enforcement functions. Section 400 and Appendix 4C of the Rules of Procedure also set forth how failure to comply with a reporting obligation will be addressed. In the event a registered entity does not submit requested data, information, or a report, the registered entity is afforded several opportunities to respond or cure a request or requirement pursuant to Attachment 1 to Appendix 4C.¹⁵ In December 2012, the Commission found that Attachment 1 to Appendix 4C “provides reasonable, measured and lawful responses to entities that are non-responsive to requests for data.”¹⁶

In its NOPR regarding proposed FAC-003-2, the Commission agrees with NERC that pursuant to section 401.3 of NERC’s Rules of Procedure, NERC and the Regional Entities can require Transmission Owners to make quarterly reports of sustained transmission outages because these reports provide information relating to compliance with the requirements of

¹⁴ Section 3.0 (emphasis added).

¹⁵ Attachment 1 to Appendix 4C to the CMEP: Process for Non-Submittal of Requested Data, Steps 1-3.

¹⁶ ROP Order at P 82.

proposed FAC-003-2.¹⁷ The Commission also states that a periodic data submittal is a requirement to provide compliance information pursuant to section 3.6 of NERC’s Compliance Monitoring and Enforcement Program.¹⁸

Commission regulations further provide that all users, owners and operators of the Bulk-Power System “subject to the Commission’s reliability jurisdiction. . .shall comply with applicable Reliability Standards, the Commission’s regulations, and applicable Electric Reliability Organization. . .Rules made effective under this part.”¹⁹ The regulations also provide that “[e]ach user, owner or operator of the Bulk-Power System within the United States. . .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. . .”²⁰ It is, therefore, appropriate for NERC and the Regional Entities to enforce the reporting obligation in proposed FAC-003-2 pursuant to section 400 of NERC’s Rules of Procedure and Appendix 4C to ensure that this data continues to be submitted for compliance and enforcement of the proposed Reliability Standard.

SVP incorrectly cites section 1600 of the Rules of Procedure as the only mechanism for the reporting obligation in proposed FAC-003-2. While section 1600 of the Rules of Procedure provides NERC with the authority to collect data, the procedure under section 1600 does not supersede the application of section 400 and Appendix 4C with respect to the enforcement of Reliability Standards. NERC respectfully requests that the Commission approve the placement of the reporting obligation in the “Additional Compliance Information” section and uphold the

¹⁷ NOPR at P 94.

¹⁸ *Id.* (citing NERC Rules of Procedure, Appx. 4C § 3.6).

¹⁹ 18 C.F.R. § 39.2(b) (2012).

²⁰ 18 C.F.R. § 39.2(d) (2012); *see also* Attachment 1 to Appendix 4C to the NERC Rules of Procedure.

data reporting obligation as mandatory and enforceable under the NERC Rules of Procedure consistent with these comments.

C. Footnote 2 of Proposed FAC-003-2 Does Not Exclude Activity by a Transmission Owner's Employee or Contractor

In proposed FAC-003-2, footnote 2 explains that Requirements R1 and R2 do not apply to certain conditions or scenarios outside the Transmission Owner's control that may lead to encroachments. NERC explains in its Petition that the footnote "does not exempt the Transmission Owner from responsibility for encroachments caused by activities performed by their own employees or contractors."²¹ A number of commenters have raised concerns regarding the footnote. The footnote reads:

This requirement does not apply to circumstances that are beyond the control of a Transmission 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 Transmission 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 right to exercise its full legal rights on the [Right-of-Way].²²

In its comments, Bonneville Power Administration ("Bonneville") states that it understands and accepts that Transmission Owners will be held liable for the actions of its employees and contractors, but believes that under some circumstances exceptions to this liability should be considered.²³ Bonneville provides examples of certain unpredictable events that could occur (such as equipment failure, rope breakage, or hidden tree defect, etc.) resulting in a Requirement R1 or R2 encroachment that Bonneville argues warrants an exemption.

²¹ NERC Petition at 23.

²² *Id.*, Ex. A at 4.

²³ See Bonneville Dec. 21, 2012 Comments.

Bonneville argues that placing this liability on the Transmission Owner will have potentially significant economic cost impacts such as increasing amounts on liability insurance and performance bonds.

Southern Company Services, Inc. (“Southern”) does not agree with NERC’s interpretation of footnote 2 and, accordingly, urges the Commission to clearly reject it when acting on the NOPR.²⁴ Southern argues that NERC’s interpretation of footnote 2 is contrary to the footnote’s plain language, which clearly and unambiguously states first that “[Requirement R1] does not apply to circumstances that are beyond the control of the Transmission Owner[.]” Moreover, Southern states that footnote 2 expressly mentions “human activity” such as the “installation, removal, or digging of vegetation” as an example of circumstances that are beyond the Transmission Owner’s control. Southern claims that NERC’s statement is clearly inconsistent with the standard’s plain language and with the intent of the FAC-003-2 standards drafting team, which, as Southern understands it, included footnote 2 in the standard, in part, to maintain the exemption from responsibility for contractor-caused violations provided under Version 1.

Pacific Gas and Electric Company (“PG&E”) also does not support NERC’s interpretation that the footnote 2 exemption should not include employees or contractors of the Transmission Owner.²⁵ PG&E argues that the intent of the exemption is to exclude outages from causes that are beyond the control of the Transmission Owner from FAC-003-2, and that footnote 2 specifically includes in its exemption human activities that are associated with vegetation management work.

NERC Response

²⁴ See Southern Dec. 21, 2012 Comments.

²⁵ See PG&E Dec. 24, 2012 Comments.

First, in response to Bonneville, NERC states that the situations Bonneville describes are best left to case-by-case analysis by the Compliance Enforcement Authority and would not be proper for an exemption.

Second, in response to Southern and PG&E, NERC's statements in its Petition regarding footnote 2 are accurate and reflect the intent of the standard drafting team. NERC consulted the standard drafting team in preparing these comments and confirmed that the intent was not to exclude activity of the employee or a contractor. Interpreting footnote 2 as Southern and PG&E suggest would insulate all errors in executing vegetation management plans, effectively encouraging mismanagement. Specific instances of error by employees or contractors in executing a vegetation management plan may be addressed through case-by-case analysis by the Compliance Enforcement Authority.

III. CONCLUSION

For the reasons stated above, NERC respectfully requests that the Commission consider these reply comments and approve the proposed Reliability Standard as filed.

Respectfully submitted,

/s/ William H. Edwards

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
William H. Edwards
Attorney
Nina H. Jenkins-Johnston
Attorney
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
william.edwards@nerc.net
nina.johnston@nerc.net

Dated: February 5, 2013

*Counsel for 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 this proceeding.

Dated at Washington, D.C. this 5th day of February, 2013.

/s/ William H. Edwards

William H. Edwards
*Attorney for North American
Electric Reliability Corporation*

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**NORTH AMERICAN ELECTRIC)
RELIABILITY CORPORATION)** **Docket No. RD13-_____**

**PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF INTERPRETATION TO BAL-002-1 –
DISTURBANCE CONTROL PERFORMANCE**

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Stacey Tyrewala
Attorney
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

*Counsel for North American Electric Reliability
Corporation*

February 12, 2013

TABLE OF CONTENTS

I. Executive Summary.....	2
II. Notices and Communications.....	4
III. Background.....	4
a. Regulatory Framework	
b. NERC Reliability Standards Development Procedure and Interpretations	
c. History of Project 2009-19, Interpretation of BAL-002-0 Requirements R4 and R5: Request for Interpretation by Northwest Power Pool Reserve Sharing Group	
IV. Justification for Approval of the Proposed Reliability Standard Interpretation.....	8
a. Procedural History of BAL-002	
b. Basis and Purpose of Reliability Standard and Interpretation	
c. Justification for Interpretation	
V. Other Issues.....	16
VI. Conclusion.....	18
 Exhibit A — Reliability Standard BAL-002-1a with Proposed Interpretation Appended	
Exhibit B — Consideration of Comments for Proposed Interpretation	
Exhibit C — Summary of the Interpretation Development Proceedings and Record of Development of Proposed Interpretation	
Exhibit D — Interpretation Drafting Team Roster for NERC Standards Development Project 2009-19	

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

NORTH AMERICAN ELECTRIC) Docket No. RD13-____
RELIABILITY CORPORATION)

**PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF INTERPRETATION TO BAL-002-1
DISTURBANCE CONTROL PERFORMANCE**

The North American Electric Reliability Corporation (“NERC”)¹ hereby requests the Federal Energy Regulatory Commission (“FERC” or the “Commission”) approve, in accordance with Section 215(d)(1) of the Federal Power Act (“FPA”)² and Section 39.5 of the Commission’s regulations, 18 C.F.R. § 39.5 (2012), a proposed interpretation to Reliability Standard —BAL-002-1–Disturbance Control Performance, which was approved by the NERC Board of Trustees on November 7, 2012. Upon Commission approval of the interpretation, the standard will be referred to as BAL-002-1a.³

BAL-002-1 is applicable to Balancing Authorities, Reserve Sharing Groups⁴ and Regional Reliability Organizations and maintains interconnection frequency by setting

¹ NERC has been certified by the Commission as the electric reliability organization (“ERO”) in accordance with Section 215 of the Federal Power Act. The Commission certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006) (“ERO Certification Order”). Unless otherwise designated, all capitalized terms shall have the meaning set forth in the Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

² 16 U.S.C. § 824o (2012).

³ See NERC Standards Numbering Convention at 2 (“If a standard has an approved Interpretation, the standard identification will also have a lower case letter after the version number.”) *available at*: http://www.nerc.com/files/NERC_Standards_Numbering_Convention_2009Sept14.pdf.

⁴ As defined in the Glossary of Terms Used in NERC Reliability Standards, a Reserve Sharing Group is a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority’s use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in

the Balancing Authority's (or Reserve Sharing Group's or Regional Reliability Organization's) time limit for balancing real power (MW) demand and supply following the sudden failure of generation.

I. EXECUTIVE SUMMARY

The Resource and Demand Balancing ("BAL") group of Reliability Standards ensure that resources and demand are balanced to maintain interconnection frequency within limits. The purpose of the BAL-002 Disturbance Control Performance Reliability Standard is to ensure the Balancing Authority is able to utilize its Contingency Reserve⁵ to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance.

Reliability Standard BAL-002-1 establishes: (1) the generic requirements that each applicable entity should use to determine the amount and type of contingency reserves that will be needed to meet a metric called the Disturbance Control Standard ("DCS"); (2) how to calculate the DCS metric; (3) procedures to be used in calculating DCS for reserve sharing groups; (4) a 15 minute default disturbance recovery period; (5) a 90 minute default Contingency Reserve restoration period; and (6) the requirement that Balancing Authorities have access to Contingency Reserves to respond to loss of generation, but not loss of load.

A Reportable Disturbance is "[a]ny event that causes an ACE^[6] change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe

quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

⁵ The term "Contingency Reserve" is defined in the NERC Glossary of Terms Used in Reliability Standards as "The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements."

⁶ The term "Area Control Error" or "ACE" is defined in the NERC Glossary of Terms Used in Reliability Standards as "the instantaneous difference between net actual and scheduled interchange, taking

contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.”⁷

The proposed interpretation clarifies that: (1) a Disturbance that exceeds the most severe single Contingency,⁸ regardless if it is a simultaneous Contingency or non-simultaneous multiple Contingency, would be a reportable event, but would be excluded from compliance evaluation; (2) a pre-acknowledged Reserve Sharing Group would be treated in the same manner as an individual Balancing Authority; however, in a dynamically allocated Reserve Sharing Group, exclusions are only provided on a Balancing Authority member by member basis; and (3) an excludable Disturbance was an event with a magnitude greater than the magnitude of the most severe single Contingency.

The proposed interpretation clarifies that BAL-002-1 is intended to be read as an integrated whole and relies in part on information in the Compliance section of the Reliability Standard.⁹ The proposed interpretation is necessary to prevent Registered Entities from shedding load to avoid possible violations of BAL-002, a result that is inconsistent with reliability principles. As the Commission has acknowledged, the Requirements are the most critical element of a Reliability Standard,¹⁰ however, other

into account the effects of Frequency Bias including correction for meter error.” Available here:

http://www.nerc.com/files/Glossary_of_Terms.pdf.

⁷ See Glossary of Terms Used in NERC Reliability Standards, available here:

http://www.nerc.com/files/Glossary_of_Terms.pdf.

⁸ Defined in the NERC Glossary of Terms Used in Reliability Standards as “[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.” Available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

⁹ A Reliability Standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the Bulk Power System. The components of a Reliability Standard include mandatory Requirements, elements necessary to demonstrate compliance and monitor and assess compliance with Requirements, and an informational section.

¹⁰ *Mandatory Reliability Standards for the Bulk Power System*, Notice of Proposed Rulemaking, 71 FR 64,770 (Nov. 3, 2006), FERC Stats. & Regs., Vol IV, Proposed Regulations, ¶ 32,608 (2006) at P 105

information in a Reliability Standard, including in the Compliance section, can and should be used to clarify ambiguities. The proposed interpretation of BAL-002-1 neither expands on any Requirement nor explains how to comply with any Requirement, and provides guidance on the meaning of Requirements R4 and R5 and their sub-parts. For these reasons, NERC respectfully requests that the Commission approve the proposed interpretation.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:¹¹

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco*
Senior Vice President and General Counsel
Holly A. Hawkins*
Assistant General Counsel
Stacey Tyrewala*
Attorney
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

III. BACKGROUND

The following background section sets forth: (a) the regulatory framework applicable to NERC interpretations; (b) NERC’s development procedures for

(“The most critical element of a Reliability Standard is the Requirements.”); *see also Order No. 693* at P 254 (“Where a Reliability Standard can be improved by providing missing Measures or Levels of Non-Compliance or by clarifying ambiguities with respect to Measures or Levels of Non-Compliance, we approve the Reliability Standard and concurrently direct NERC to modify it accordingly.”)(internal citation omitted).

¹¹ Persons to be included on the Commission’s service list are indicated with an asterisk. NERC requests waiver of the Commission’s rules and regulations to permit the inclusion of more than two people on the service list.

Interpretations; and (c) the History of Project 2009-19, the request for Interpretation by the Northwest Power Pool Reserve Sharing Group.

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,¹² Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation’s bulk power system, and with the duties of certifying an electric reliability organization (“ERO”) that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215 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.¹³

Section 39.5(a) of the Commission’s regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to be made effective. The Commission has the regulatory responsibility to approve standards that protect the reliability of the bulk power system and to ensure that such standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest.

b. NERC Reliability Standards Development Procedure and Interpretations

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes

¹² 16 U.S.C. § 824o (2012).

¹³ See Section 215(b)(1)(“All users, owners and operators of the bulk-power system shall comply with reliability standards that take effect under this section.”).

Manual.¹⁴ 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 satisfy certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system.

All persons who are directly or materially affected by the reliability of the North American bulk power system are permitted to request an interpretation of a Reliability Standard, as discussed in NERC's *Reliability Standards Development Procedure*, which is incorporated into the Rules of Procedure as Appendix 3A. Upon request, NERC will assemble a team with the relevant expertise to address the interpretation request and present an interpretation for industry ballot. If approved by the ballot pool and the NERC Board of Trustees, the interpretation is appended to the Reliability Standard and filed for approval with the Commission and applicable governmental authorities in Canada to be made effective when approved. When the affected Reliability Standard is next revised using the *Reliability Standards Development Procedure*, the interpretation will then be incorporated into the Reliability Standard. The Reliability Standard interpretation submitted herein was approved by the NERC Board of Trustees on November 7, 2012.

c. History of Project 2009-19, Interpretation of BAL-002-0 Requirements R4 and R5: Request for Interpretation by Northwest Power Pool Reserve Sharing Group

A complete summary of the development of Project 2009-19 is included herein as

Exhibit C. On September 2, 2009, Northwest Power Pool Reserve Sharing Group

¹⁴ The NERC Rules of Procedure are available here: <http://www.nerc.com/page.php?cid=1%7C8%7C169>. The current NERC Standard Processes Manual is available here: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf.

(“NWPP”) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0, Disturbance Control Performance. The specific areas NWPP requested clarification of are:

- (1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
- (2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when
 - o (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group, and
 - o (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and
- (3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

NWPP requested clarification in order “to avoid applications of BAL-002-0 that would render the reserve requirement in R3.1 of BAL-002-0 (which calls for ‘enough Contingency Reserve to cover the most severe single Contingency’) meaningless.”¹⁵

¹⁵ See Request for Interpretation at p. 3.

NWPP stated that:

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.*, Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that “An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.”)

IV. JUSTIFICATION FOR APPROVAL OF THE PROPOSED RELIABILITY STANDARD INTERPRETATION

The following is set forth below: (a) the procedural history of Reliability Standard BAL-002; (b) the basis and purpose of Reliability Standard BAL-002 and the proposed Interpretation; and (c) the justification for the proposed Interpretation.

a. Procedural History of BAL-002

BAL-002-0 was submitted for Commission approval in Docket No. RM06-16-000 and was accepted in Order No. 693.¹⁶ BAL-002-0 was revised (and therefore renumbered as BAL-002-1) to address two Commission directives from paragraph 321 of Order No. 693. BAL-002-1 was submitted in Docket No. RD10-15-000 and was accepted by the Commission via letter order on January 10, 2011.¹⁷

b. Basis and Purpose of Reliability Standard and Interpretation

¹⁶ *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).
¹⁷ 134 FERC ¶ 61,015 (2011).

As noted above, the purpose of BAL-002 is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Generator failures are far more common than significant losses of load, and because Contingency Reserve activation does not typically apply to the loss of load, the application of BAL-002 is limited to the loss of supply and does not apply to the loss of load.

Requirement R4 of BAL-002-1 requires Balancing Authorities or Reserve Sharing Groups to meet the Disturbance Recovery Criterion within the Disturbance Recovery period for 100% of Reportable Disturbances.¹⁸ Requirement R5 of BAL-002-1 requires each Reserve Sharing Group to comply with the DCS.¹⁹ The proposed

¹⁸

BAL-002-1, Requirement R4:

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.

¹⁹

BAL-002-1, Requirement R5:

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

interpretation clarifies that although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation and there is no violation of BAL-002-1. This proposed interpretation is based in part on the language in the BAL-002, Additional Compliance Information section, which provides that “if the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, *the loss shall be reported, but excluded from compliance evaluation.*”²⁰ (emphasis added).

c. Justification for Interpretation

The proposed interpretation clarifies that BAL-002-1 is intended to be read as an integrated whole and that although a Disturbance that exceeds the most severe single

²⁰ Part D. of BAL-002-1 is the Compliance section of the standard. Section 1.5 of Part D, Additional Compliance Information is as follows:

1.5. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation.

As the Commission has acknowledged, the Requirements are the most critical element of a Reliability Standard.²¹ However, other information in the Reliability Standard, including in the Compliance section, can and should be used to clarify ambiguities. For example, Measures are intended to gauge or document compliance and the violation of a Measure will almost always result in the violation of a Requirement. The mere fact that Measures appear in a different section of the Reliability Standard does not diminish the ability of a Measure to add clarity to the implementation of a Requirement.

While a Reliability Standard does not require additional information (other than Requirements) to be enforceable, such information is included for guidance purposes, and a Reliability Standard should be read as an integrated whole and not just as an isolated series of Requirements. However, an interpretation cannot and should not be used to substantively *change* a Reliability Standard, as acknowledged on the NERC form for a request for an interpretation of a Reliability Standard. The Standard Process Manual states that a “valid Interpretation response provides additional clarity about one or more Requirements, but does not expand on any Requirement and does not explain how to comply with any Requirement.”²² The instant interpretation of BAL-002-1 neither expands on any Requirement nor explains how to comply with any Requirement, and provides guidance on the meaning of Requirements R4 and R5 and their sub-parts.

²¹ *Mandatory Reliability Standards for the Bulk Power System*, Notice of Proposed Rulemaking, 71 FR 64,770 (Nov. 3, 2006), FERC Stats. & Regs., Vol IV, Proposed Regulations, ¶ 32,608 (2006) at P 105 (“The most critical element of a Reliability Standard is the Requirements.”); *see also Order No. 693* at P 254 (“Where a Reliability Standard can be improved by providing missing Measures or Levels of Non-Compliance or by clarifying ambiguities with respect to Measures or Levels of Non-Compliance, we approve the Reliability Standard and concurrently direct NERC to modify it accordingly.”)(internal citation omitted).

²² Standard Process Manual at p. 27.

As NWPP noted in its Request for Interpretation, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the Reliability Standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Interpretation Request:

Question 1: Although a Disturbance²³ that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?

In response to NWPP's interpretation request, the interpretation drafting team developed, and the industry stakeholders approved, the following interpretation:

Response:

*The IDT agrees that the Disturbance would be excluded from compliance. The BAL-002 **Additional Compliance Information** section clearly states:*

Simultaneous Contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

For clarity the IDT would like to explain the Team's basis concerning some of the terminology used.

Most Severe Single Contingency (MSSC) – *this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known*

²³ Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction. Although Requirement R3.1 mandates an annual “review” that does not mean an annual value. Note that Requirement R3.1 determines a “prospective” MSSC. MSSC is a variable that the BA knows and operates to in real time. The largest operating generator is known and monitored by a BA. The largest known common mode failure is predefined for the BA; the largest single firm transaction is approved by the BA. Thus the BA knows its MSSC which can vary from hour to hour and minute to minute.

To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC).

An undefined “common mode” failure can occur but it is exempted from R4’s requirement to meet the BA’s or RSG’s disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition.

BAL-002 has two categories (1) Compliance and reporting (for Reportable Disturbances that must comply with the disturbance recovery criteria within the Disturbance Recovery Period) and (2) Reporting only (for specified disturbances and system conditions) events that are excluded from meeting Requirement R4.

*The **Compliance and reporting category** is designed to be used to accumulate all DCS events that are subject to compliance to BAL-002 Requirement R4 (i.e. recover ACE within 15 minutes). These include all single assets as well as all pre-defined common mode failures. The standard originally created Ri (the average percent recovery for a Reportable Disturbance) as a measure of the quarterly compliance for Reportable Disturbances. Where all events greater than 80% were mandatory to report and those less than 80% were permitted to be reported (thus encouraging reporting smaller events).*

*The **Reporting only category** is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC.*

*The **Performance Standard Reference document** initially included with the DCS standard does states “Where RSGs exist, the Regional Reliability Council is to decide either to report on a BA basis or an RSG basis. If an RSG has dynamic membership then... required ...to report on a BA basis.*

Interpretation Request:

Question 2: With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group,

does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?

In response to NWPP's interpretation request, the interpretation drafting team developed, and the industry stakeholders approved, the following interpretation:

Response:

Requirement R5 is directed to RSGs, where RSG is defined in the NERC Glossary as:

A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

The standard provides flexibility to BAs regarding the use or non-use of RSGs (Requirement R1.1). Requirement R2 affords the members flexibility in how they organize themselves.

Requirement R1.1 allows, at the option of a BA, or RSG to take on all or part of the responsibilities that BAL-002 places on a BA. However, Requirement R5 allows a BA to "call for activation" of reserves [aka dynamic allocation of membership] moreover, there is no ad hoc recognition of such an RSG's multiple contingencies since a contingency in one BA may or not be referred to the RSG, and the simultaneous contingency in another BA is unknown.

The Technical Document does allow for a pre-acknowledged RSG to report on a composite basis. It can be interpreted that such a pre-acknowledged RSG entity assumes all of the obligations and rights afforded to a single BA and in that case such an RSG would be afforded the same Exclusions as the Exclusions afforded a BA.

In summary, the interpretation is as follows:

- *The Standard was written to provide pre-acknowledged RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a pre-acknowledged RSG the exclusion rules would be used*

in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period.

The standard, while recognizing dynamically allocated RSGs, does NOT provide the members of dynamically allocated RSGs exclusions from DCS compliance evaluation on an RSG basis. For members of dynamically allocated RSGs, the exclusions are provided only on a member BA by member BA basis.

As demonstrated in **Exhibit B**, the interpretation drafting team addressed the meaning of the terms “pre-acknowledged RSGs” and “dynamically allocated RSGs” used in response to Question 2. The interpretation drafting team explained that the terms “pre-acknowledged” and “dynamic” were used in the common English terms to mean (i) an RSG that is “recognized ahead of time rather than after-the-fact;” and (ii) an RSG that is used on an on-call basis and thus its responding members are “not static.” The interpretation drafting team explained that a “pre-acknowledged RSG” knows who is participating and who is not. However, a “dynamically allocated RSG” operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate. The Technical Document referenced in the interpretation is available here:

http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf.

Interpretation Request:

Question 3: Clarify the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

In response to NWPP's interpretation request, the interpretation drafting team developed, and the industry stakeholders approved, the following interpretation:

Response:

*The **Additional Compliance Information** section clearly states:*

***Simultaneous contingencies** – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the Most Severe Single Contingency, the loss shall be reported, but excluded from compliance evaluation.*

Although Requirement R3 does mandate that a BA or RSG activate sufficient Contingency Reserves to comply with DCS for every Reportable Disturbance, there is no requirement to comply with or even report disturbances that are below the Reportable Disturbance level. The averaging obligation does incent calculation and reporting of such lesser events.

If a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency. Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (see, e.g., Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, Disturbance Control Standard, DCS, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

V. OTHER ISSUES

While the proposed interpretation differs from the settlement reached in *PacifiCorp*,²⁴ in which NERC and Commission Enforcement agreed that language

²⁴ *PacifiCorp*, 137 FERC ¶ 61,176 at n. 5 (2011) ("Enforcement and NERC concluded that BAL-002-0 Requirement R4 applies any time there is a Reportable Disturbance regardless of the number or type of contingencies and that this requirement is not altered by the Additional Compliance Information in

included in the Additional Compliance Information section of the standard is guidance and did not require either the Commission or NERC to provide an exclusion from a compliance action, the PacifiCorp settlement is limited to its specific facts and as a settlement agreement, does not establish legal precedent. The proposed interpretation is necessary in order to prevent Registered Entities from shedding load to avoid possible violations of BAL-002, a result that is inconsistent with reliability principles.

Section D.1.4 of BAL-002-0. In Order No. 693, in which the Commission approved this standard, among others, the Commission emphasized that compliance was determined by the requirements, not other parts of a Reliability Standard: ‘while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstance of its use, ownership or operation of the Bulk-Power System.’ *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 253, *order on reh’g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).”).

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve the interpretation as set forth in **Exhibit A**, effective as proposed herein.

Respectfully submitted,

/s/ Stacey Tyrewala

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595– facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Stacey Tyrewala
Attorney
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

*Counsel for the North American Electric
Reliability Corporation*

Dated: February 12, 2013

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 12th day of February, 2013.

/s/ Stacey Tyrewala

Stacey Tyrewala

*Attorney for North American Electric
Reliability Corporation*

Exhibit A

Reliability Standard BAL-002-1a with Proposed Interpretation Appended

A. Introduction

1. **Title:** **Disturbance Control Performance**
2. **Number:** BAL-002-1a
3. **Purpose:** The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.
4. **Applicability:**
 - 4.1. Balancing Authorities
 - 4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)
 - 4.3. Regional Reliability Organizations
5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

- 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.
 - R1.1.** A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.
- R2.** Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:
 - R2.1.** The minimum reserve requirement for the group.
 - R2.2.** Its allocation among members.
 - R2.3.** The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.
 - R2.4.** The procedure for applying Contingency Reserve in practice.
 - R2.5.** The limitations, if any, upon the amount of interruptible load that may be included.
 - R2.6.** The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.
- R3.** Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.
 - R3.1.** As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently

than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

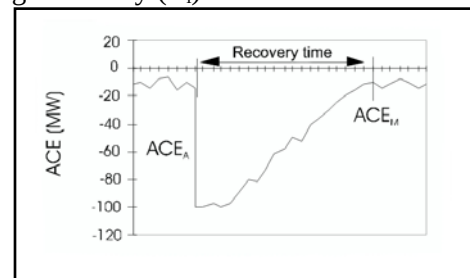
R6.2. The default Contingency Reserve Restoration Period is 90 minutes.

C. Measures

M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

For loss of generation:

if $ACE_A < 0$
then



$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$

if $ACE_A \geq 0$

then

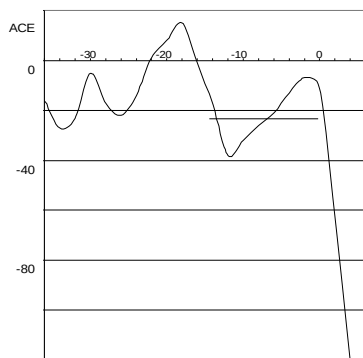
$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

where:

- MW_{Loss} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15 \text{ min}}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{Loss} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of $ACE_A = -25 \text{ MW}$.



The average percent recovery is the arithmetic average of all the calculated R_i 's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, “NERC Control Performance Standard Survey – All Interconnections” to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Entity must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.5. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable

estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

3. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	August 5, 2010	Adopted by the NERC Board of Trustees	Modified to address Order No. 693 Directives contained in paragraph 321.
1a	November 7, 2012	Interpretation Adopted by the NERC Board of Trustees	

Appendix 1

Request for an Interpretation of a Reliability Standard	
Date submitted:	September 2, 2009
Date accepted:	September 2, 2009
Contact information for person requesting the interpretation:	
Name:	Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization:	Northwest Power Pool Reserve Sharing Group
Telephone:	503-445-1074
E-mail:	jerry.rust@nwpp.org
Identify the standard that needs clarification:	
Standard Number (include version number):	BAL-002-0
Standard Title:	Disturbance Control Performance
Identify specifically what requirement needs clarification:	
<u>Requirement Number and Text of Requirement:</u>	
B. Requirements	
* * *	
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is: R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value. R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.	
* * *	
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. * * * Compliance may be demonstrated by either of the following two methods: R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to	

reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

D. Compliance

1.4 Additional Compliance Information

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Clarification needed:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

- (1) although a Disturbance¹ that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
- (2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and
- (3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve

¹ Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for “enough Contingency Reserve to cover the most severe single Contingency”) meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute “Reportable Disturbances.” See Section 1.4 of Part D of BAL-002-0 (where the “Additional Compliance Information” includes a definition of “Reportable Disturbance”).

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (see, e.g., Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that “An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.”)

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Response:

The Balancing Authority Controls Standard Drafting Team was originally assigned to provide a response to the interpretation request. The original interpretation failed to achieve a two-thirds approval from the industry. NERC appointed a new IDT to develop this interpretation. On July 24, 2012, the team provided the following response to the questions raised:

Question 1: Although a Disturbance² that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from

² Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?

Response: The IDT agrees that the Disturbance would be excluded from compliance. The BAL-002 **Additional Compliance Information section** clearly states:

Simultaneous Contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

For clarity the IDT would like to explain the Team's basis concerning some of the terminology used.

Most Severe Single Contingency (MSSC) – this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction. Although Requirement R3.1 mandates an annual "review" that does not mean an annual value. Note that Requirement R3.1 determines a "prospective" MSSC. MSSC is a variable that the BA knows and operates to in real time. The largest operating generator is known and monitored by a BA. The largest known common mode failure is predefined for the BA; the largest single firm transaction is approved by the BA. Thus the BA knows its MSSC which can vary from hour to hour and minute to minute.

To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC).

An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition.

BAL-002 has two categories (1) Compliance and reporting (for Reportable Disturbances that must comply with the disturbance recovery criteria within the Disturbance Recovery Period) and (2) Reporting only (for specified disturbances and system conditions) events that are excluded from meeting Requirement R4 requirement.

The **Compliance and reporting category** is designed to be used to accumulate all DCS events that are subject to compliance to BAL-002 Requirement R4 (i.e. recover ACE within 15 minutes). These include all single assets as well as all pre-defined common mode failures. The standard originally created R_i (the average percent recovery for a Reportable Disturbance) as a measure of the quarterly compliance for Reportable Disturbances. Where all events greater than 80% were mandatory to report and those less than 80% were permitted to be reported (thus encouraging reporting smaller events).

The **Reporting only category** is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single

event and thus considered as the MSSC.

The **Performance Standard Reference document** initially included with the DCS standard does states “Where RSGs exist, the Regional Reliability Council is to decide either to report on a BA basis or an RSG basis. If an RSG has dynamic membership then... required ...to report on a BA basis.

Question 2: With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?

Response: Requirement R5 is directed to RSGs, where RSG is defined in the NERC Glossary as:

A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority’s use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

The standard provides flexibility to BAs regarding the use or non-use of RSGs (Requirement R1.1). Requirement R2 affords the members flexibility in how they organize themselves.

Requirement R1.1 allows, at the option of a BA, or RSG to take on all or part of the responsibilities that BAL-002 places on a BA. However, Requirement R5 allows a BA to “call for activation” of reserves [aka dynamic allocation of membership] moreover, there is no ad hoc recognition of such an RSG’s multiple contingencies since a contingency in one BA may or not be referred to the RSG, and the simultaneous contingency in another BA is unknown.

The Technical Document does allow for a pre-acknowledged RSG to report on a composite basis. It can be interpreted that such a pre-acknowledged RSG entity assumes all of the obligations and rights afforded to a single BA and in that case such an RSG would be afforded the same Exclusions as the Exclusions afforded a BA.

In summary, the interpretation is as follows:

- The Standard was written to provide pre-acknowledged RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a pre-acknowledged RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable

Disturbance but before the end of the Disturbance Recovery Period. The standard, while recognizing dynamically allocated RSGs, does NOT provide the members of dynamically allocated RSGs exclusions from DCS compliance evaluation on an RSG basis. For members of dynamically allocated RSGs, the exclusions are provided only on a member BA by member BA basis.
Question 3: Clarify the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).
Response: The Additional Compliance Information section clearly states: Simultaneous contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the Most Severe Single Contingency, <u>the loss shall be reported, but excluded from compliance evaluation.</u> Although Requirement R3 does mandate that a BA or RSG activate sufficient Contingency Reserves to comply with DCS for every Reportable Disturbance, there is no requirement to comply with or even report disturbances that are below the Reportable Disturbance level. The averaging obligation does incent calculation and reporting of such lesser events. If a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude. An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency. Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (<i>see, e.g., Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007)</i>, which provides in Section D, <i>Disturbance Control Standard, DCS</i>, that “An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.”)

Exhibit B

Consideration of Comments for Proposed Interpretation

Project 2009-19

Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group

Status:

The interpretation was adopted by the NERC Board of Trustees on November 7, 2012, and is pending regulatory approval.

Summary:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

1. although a Disturbance^{1[1]} that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
2. with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and
3. the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

^{1[1]} Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Purpose / Industry Need:

In accordance with the Reliability Standards Development Procedure, the interpretation must be posted for a 30-day pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

Appeal:

On January 17, 2012 NERC received a Level 1 Appeal for inaction from the ISO/RTO Council's Standards Review Committee on Project 2009-19 - Northwest Power Pool's Reserve Sharing Group's request for an interpretation of BAL-002-0, Requirement R4. The appellants asked for clarity on the following issues:

- Did NERC, or the Standards Committee, convene the IDT, after comments were received. What industry and/or NERC personnel made up the IDT?
- What accounted for the Standards Committee placing the RFI on hold (in October 2010) and the delay in processing the RFI prior to the Standards Committee 2011 action to place on hold pending Interpretations?'
- Do the Standards Committee Agendas correctly indicate that NERC considered the RFI an invalid request, and if so, why?

[IRC Appeal](#)

[Data Information Request and Exhibits](#)

[NERC Response](#)

Draft	Action	Dates	Results	Consideration of Comments
Draft 2 Northwest Power Pool RSG BAL-002-0 Interpretation Request for Interpretation	Recirculation Ballot Info Vote>>	09/28/12 - 10/08/12	Summary Full Record	
Draft 2 Northwest Power Pool RSG BAL-002-0 Interpretation Request for Interpretation	Successive Ballot Updated Info Info Vote>>	08/23/12 - 09/04/12 (closed)	Summary Full Record	
Supporting Documents: Unofficial Comment Form (Word)	Formal Comment Submit	07/25/12 - 09/04/12 (closed)	Comments Received	Consideration of Comments (1)

	Comments>>			
	Join Ballot Pool>>	07/25/12 - 08/23/12 (closed)		
Draft 1 Northwest Power Pool RSG BAL-002-0 Request for Interpretation Interpretation	Initial Ballot Info Vote>>	02/15/10 - 02/26/10 (closed)	Summary Full Record	
	Pre-ballot Review Info Join>>	01/15/10 - 02/15/10 (closed)		

Consideration of Comments

Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group Project 2009-19

The Project 2009-19 Drafting Team thanks all commenters who submitted comments on the proposed Interpretation of BAL-002-0 (R4, R5, and Section D 1.4) for the Northwest Power Pool Reserve Sharing Group. The interpretation was posted for a 45-day public comment period from July 25, 2012 through September 4, 2012. Stakeholders were asked to provide feedback on the interpretation and associated documents through a special electronic comment form. There were 25 sets of comments, including comments from approximately 96 different people from approximately 56 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Of those responders that disagreed with the interpretation, the majority questioned the use of the “Additional Compliance Information” in providing an interpretation of the requirements. The IDT explained that the NERC BOT specifically allowed the use of the reference materials in developing this interpretation. The IDT further explained that the NERC BOT recognized that in the conversion of NERC Policies to Version 0 standards, critical information was placed in sections outside of the requirements themselves and that strict construction policy in the case of the DCS standard was not consistent with the standard itself.

A few of the responders questioned how an RSG was to respond and the amount of time allowed to respond. The IDT explained that the clarification requested by NWPP was not about how an RSG was to respond or the amount of time allowed but instead focused on under what conditions could a Disturbance be excluded for compliance evaluation.

Some responders felt that the terms “pre-acknowledged RSGs” and “dynamically allocated RSGs” were not defined and therefore should not be used. The IDT explained that the terms “pre-acknowledged” and “dynamic” were used in the common English terms to be an RSG that is “recognized ahead of time rather than an after-the-fact”. And an RSG that is used on an on-call basis and thus its responding members are “not static”, respectively.

A few responders questioned why the rules were different for an RSG. The IDT explained that a “pre-acknowledged RSG” knows who is participating and who is not. However, a “dynamically allocated RSG” operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate.

A few responders questioned which version of the BAL-002 (BAL-002-0 or BAL-002-1) this interpretation would apply to. The IDT explained that although the interpretation was requested for BAL-002-0 it would apply to BAL-002-1 as well.

All comments submitted may be reviewed in their original format on the standard's [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 Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.¹

¹ The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

1. Do you agree with Response 1 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language..... 10
2. Do you agree with Response 2 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language..... 25
3. Do you agree with Response 3 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language..... 31

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X
	Additional Member	Additional Organization	Region	Segment	Selection								
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10									
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2									
3.	Greg Campoli	New York Independent System Operator	NPCC	2									
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1									
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1									
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10									
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5									
8.	Kathleen Goodman	ISO - New England	NPCC	2									
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1									
10.	Michael Lombardi	Northeast Utilities	NPCC	1									

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
11. Randy MacDonald		New Brunswick Power Transmission	NPCC	9										
12. Bruce Metruck		New York Power Authority	NPCC	6										
13. Lee Pedowicz		Northeast Power Coordinating Council	NPCC	10										
14. Robert Pellegrini		The United Illuminating Company	NPCC	1										
15. Si-Truc Phan		Hydro-Quebec TransEnergie	NPCC	1										
16. David Ramkalawan		Ontario Power Generation, Inc.	NPCC	5										
17. Michael Jones		National Grid	NPCC	1										
18. Brian Robinson		Utility Services	NPCC	8										
19. Silvia Parada Mitchell		NextEra Energy, LLC	NPCC	5										
20. Donald Weaver		New Brunswick System Operator	NPCC	2										
21. Michael Schiavone		National Grid	NPCC	1										
22. Wayne Sipperly		New York Power Authority	NPCC	5										
23. Ben Wu		Orange and Rockland Utilities	NPCC	1										
24. Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC	3										
2.	Group	Terry Bilke	ISO-RTO Standards Review Committee			X								
Additional Member		Additional Organization	Region	Segment	Selection									
1. Ben Li		IESO	NPCC	2										
2. Steve Meyers		ERCOT	ERCOT	2										
3. Greg Campoli		NYISO	NPCC	2										
4. Ali Miremadi		CAISO	WECC	2										
5. Charles Yeung		SPP	SPP	2										
6. Kathleen Goodman		NEISO	NPCC	2										
7. Stephanie Monzon		PJM	RFC	2										
3.	Group	Ben Engelby	ACES Power Marketing Standards Collaborators							X				
Additional Member		Additional Organization	Region	Segment	Selection									
1. Megan Wagner		Sunflower Electric Power Corporation	SPP	1										
4.	Group	Pablo Onate	El Paso Electric		X		X		X	X				
Additional Member		Additional Organization	Region	Segment	Selection									
1. Dennis Malone		El Paso Electric	WECC	1										
2. Tracy Van Slyke		El Paso Electric	WECC	3										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3.	David Hawkins	El Paso Electric	WECC 5										
4.	Tony Soto	El Paso Electric	WECC 6										
5.	Group	Greg Rowland	Duke Energy	X		X		X	X				
Additional Member Additional Organization Region Segment Selection													
1.	Doug Hils	Duke Energy	RFC 1										
2.	Lee Schuster	Duke Energy	FRCC 3										
3.	Dale Goodwine	Duke Energy	SERC 5										
4.	Greg Cecil	Duke Energy	SERC 6										
6.	Group	David Dockery	Associated Electric Cooperative Inc - JRO00088	X		X		X	X				
Additional Member Additional Organization Region Segment Selection													
1.	Central Electric Power Cooperative		SERC 1, 3										
2.	KAMO Electric Cooperative		SERC 1, 3										
3.	M & A Electric Power Cooperative		SERC 1, 3										
4.	Northeast Missouri Electric Power Cooperative		SERC 1, 3										
5.	N.W. Electric Power Cooperative, Inc.		SERC 1, 3										
6.	Sho-Me Power Electric Cooperative		SERC 1, 3										
7.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				
Additional Member Additional Organization Region Segment Selection													
1.	James	Murphy	WECC 1										
2.	Fran	Halpin	WECC 5										
3.	Erika	Doot	WECC 3, 5, 6										
8.	Group	Robert Rhodes	SPP Standards Review Group		X								
Additional Member Additional Organization Region Segment Selection													
1.	C. J. Brown	Southwest Power Pool	SPP 2										
2.	Ron Gunderson	Nebraska Public Power District	MRO 1, 3, 5										
3.	Tiffany Lake	Westar Energy	SPP 1, 3, 5, 6										
4.	Heath Martin	Southwest Power Pool	SPP 2										
5.	Terry Oxandale	Southwest Power Pool	SPP 2										
6.	Mahmood Safi	Omaha Public Power District	MRO 1, 3, 5										
7.	Katie Shea	Westar Energy	SPP 1, 3, 5, 6										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Jason Smith	Southwest Power Pool	SPP 2										
9.	Carl Stelly	Southwest Power Pool	SPP 2										
10.	Bryan Taggart	Westar Energy	SPP 1, 3, 5, 6										
9.	Group	Gerald Beckerle	SERC Operating Committee Standards Review Team	X	X	X		X	X				X
Additional Member Additional Organization Region Segment Selection													
1.	Stuart Goza	TVA	SERC 1, 3, 5, 6										
2.	Melinda Montgomery	Entergy	SERC 1, 3, 6										
3.	Oliver Burke	Entergy	SERC 1, 3, 6										
4.	Wayne Van Liere	LGE-KU	SERC 3										
5.	Marie Knox	MISO	SERC 2										
6.	Tim Hattaway	PowerSouth	SERC 1, 5										
7.	Ronnie Douglas	Electric Energy, Inc	SERC 5										
8.	Brad Young	LGE-KU	SERC 3										
9.	Steve Corbin	SERC	SERC NA										
10.	Pat Huntley	SERC	SERC NA										
11.	Robert Thomasson	Big Rivers Electric Corp	SERC 1, 3, 5										
12.	Ronnie Douglas	Electric Energy	SERC 1, 3, 5										
10.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
11.	Individual	Michael Falvo	Independent Electricity System Operator		X								
12.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
13.	Individual	Thad Ness	American Electric Power			X		X	X				
14.	Individual	Oliver Burke	Entergy Services, Inc.	X		X		X	X				
15.	Individual	John Appel	Public Utility District #1 of Chelan County	X		X		X	X			X	
16.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
17.	Individual	Carter Edge	SERC										X
18.	Individual	linda Horn	Wisconsin Electric Power Company	X		X		X					
19.	Individual	Greg Travis	Idaho Power Co.										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	XX				
21.	Individual	Anthony Jablonski	ReliabilityFirst										X
22.	Individual	Maggy Powell	Exelon Corporation	X		X		X	X				
23.	Individual	Brent Ingebrigtsen	LG&E and KU Services Company			X							
24.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
25.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Supporting Comments of "Entity Name"
Public Utility District #1 of Chelan County	Chelan PUD supports the interpretation of BAL-002-0 on behalf of the NWPP.
Electric Reliability Council of Texas, Inc.	ISO SRC
Wisconsin Electric Power Company	We are supporting the comments of MISO.

1. Do you agree with Response 1 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation, the majority questioned the use of the “Additional Compliance Information” in providing an interpretation of the requirements. The IDT explained that the NERC BOT specifically allowed the use of the reference materials in developing this interpretation. The IDT further explained that the NERC BOT recognized that in the conversion of NERC Policies to Version 0 standards, critical information was placed in sections outside of the requirements themselves and that strict construction policy in the case of the DCS standard was not consistent with the standard itself.

A few of the responders questioned how an RSG was to respond and the amount of time allowed to respond. The IDT explained that the clarification requested by NWPP was not about how an RSG was to respond or the amount of time allowed but instead focused on under what conditions could a Disturbance be excluded for compliance evaluation.

A few responders referenced ALR 2-5 and stated that this should be carried forward in the future. The IDT explained that this interpretation request was not a question about ALR 2-5. What NWPP asked was if there were two contingencies at the same time, does the standard relieve them of the responsibility to respond in the given time frame. To paraphrase the IDT response, “if a BA experiences two simultaneous contingencies where total output was greater than the BAs MSSC, the BA must respond but will not be responsible to comply with the strictures of the requirement.”

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative Inc - JRO00088	No	Remove: The final paragraph beginning with "The Performance Standard Reference document initially included..."Rationale: A text-search of BAL-002-0, downloaded from the NERC website, fails to yield any instances of the word “dynamic”, meaning that it appears nowhere within the four-corners of the BAL-002-0 Standard. Responsible Entities are subject only to the Standard’s requirements as written and within its Effective Dates 4/1/2005 to 8/5/2010, when BAL-002-1 effectively replaced it. NERC’s BOT Approved August 2, 2006 filing with The Commission appears to contain the

Organization	Yes or No	Question 1 Comment
		oldest copy of FERC approved NERC Glossary of Terms Used in Reliability Standards. It contains no instances of the word “dynamic” that correspond in any way to Reserve Sharing Group membership, although “Reserve Sharing Group” and “Reportable Disturbance” are defined within that document. Although the SDT asserts the augmented concept of RSG dynamic membership, those references within this interpretation should be stricken because the “dynamic membership” concept clearly does not exist within the “four-corners of the Standard” which was balloted and approved by industry stakeholders. Instead BAL-002-0 wording indicates that each RSG can establish its own guidance, necessary to comply with the Requirements. Requirement R2 provides each Reserve Sharing Group the flexibility concerning its policies governing how it collectively fulfills its responsibility to meet Requirements R3, R4, R5 and R6. However Requirement R5’s parenthetical does appear to provide some governance concerning a BA’s reporting within a Reserve Sharing Group when they do not call for reserve activation from its other members, that they are subject to individually reporting their performance in responding to that event. (In either case of reporting per R5 parenthetical, the RSG’s collectively-committed units’ spinning-mass and short-term governor response would have fulfilled the reliability objective of this Standard, unless the Reportable Disturbance’s magnitude was much greater than anticipated by the RSG in its entirety.)
Response: Under normal circumstances Associated Electric Cooperative Inc would be correct that only the stated requirements within the four corners of a standard can be referenced in an interpretation. In this case however, the NERC Board of Trustees specifically allowed the Interpretation Drafting Team to make use of reference materials that were created for the original NERC Policy but that in the conversion from NERC Policy to Version 0 standards those materials were placed in sections outside of the requirements themselves. The BOT recognized that strict constructionism in the case of the DCS standard was not consistent with the standard itself and those who drafted the standard.		

Organization	Yes or No	Question 1 Comment
Response 1 deals with the issue of excluding a Disturbance that exceeds the most severe single Contingency of a BA or an RSG. Response 1 does not deal with governance. A group of BAs can form an RSG (please note that despite the fact that RSG is a defined term, it does not mean that all RSGs are the same) and decide how to allocate and measure the service it will provide. However, as the cited reference (Performance Standards Guidelines) states (chapter 6, Reporting) “Where RSGs exist, the Regional Reliability Council is to decide either to report these on a BA basis or on an RSG basis.” Thus it is clearly not up to the RSG to make that decision about reporting. If the reporting were left to the RSGs then the standard would be a fill-in-the-blanks standard. The RSG would be allowed after-the-fact to decide whether or not two independent losses would be counted as a reason for not reporting. Such an approach would place the system at risk – and the original drafters of that BAL-002 recognized the need to make clear that to take advantage of this benefit, the dynamic RSG (not all RSGs just those that BAs make use of on an as needed basis) must have permission from their Region to address such events on a composite basis. The question raised by NWPP was not about allowing RSGs to respond, the question was about which conditions would exclude a disturbance that exceeded the MSSC of the BA or RSG. It is clear that for a BA any set of non-common mode contingencies that exceed its MSSC would be excluded. For an RSG that has a variable participation, that situation is by definition unclear. Since BA(1) may lose a resource equal to its MSSC and not call for reserve sharing and fail to comply with the standard, however, unknown to BA(1) is the fact that BA(2) also lost a resource at the same time. BA (2) also did not call for reserve sharing and failed to comply. However, after the fact the RSG observes the situation that as a group they would be permitted to exclude the “composite disturbance”. The original drafters recognized that fact and precluded that situation by requiring that the Regions decide which MSSC to accept for a BA and which RSGs are permitted to treat themselves as a single BA. The standard was written to serve reliability and not as a means to avoid responding to disturbances. The BOT recognized that fact and allowed the IDT to respond to the NWPP question on the basis of what the drafters meant as indicated by all available reference material and not be limited by the 4 wall of the requirements.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.

Organization	Yes or No	Question 1 Comment
Response: The interpretation was not based entirely on the requirements of BAL-002-0, but also on the Additional Compliance Information section and other reference material (See response to AECI's question 1 comment) as allowed by the BOT.		
SERC	No	The interpretations process is not an appropriate mechanism to address a compliance monitoring and enforcement issue. Further, the words in the requirements do not support the interpretation, no matter how much the interpretation reflects how the industry and ERO have historically approached the Disturbance Control Standard. The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Specifically, Requirement 1 requires each Balancing Authority to have access to and/or operate Contingency Reserve to respond to Disturbances. Prior to penalties and sanctions under Section 215, the consequence of failing DCS was to require an increase in contingency reserves. This is the “compliance evaluation” referred to under Section D. The expectation is that Balancing Areas respond to the loss of resources regardless of magnitude to restore ACE and minimize the risk to reliable operation of being “out of balance”. There was recognition, however, that interconnected operations increased the reliability of the grid by reducing the consequences of a single area being out of balance at any given time and thus allowed the collective greater utilization of installed capacity to serve load rather than retain it as contingency reserves. Thus, the concept of “most severe single contingency” (MSSC) as a criterion against which to require additional contingency reserve was employed and for large contingencies may require more time to respond. Fifteen minutes is a "benchmark" time-frame that is reasonable to expect a Balancing Area to recover from a credible contingency. There is nothing magical about that time (it used to be 10 minutes), but the BA should not "lean" on the system longer than is

Organization	Yes or No	Question 1 Comment
		necessary regardless of the magnitude. Performance outside this benchmark can only be determined by an inspection of the facts and circumstances of each instance. All Balancing Authorities and Reserve Sharing Groups are required to review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies. The NERC glossary defines Contingency as the “unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element”. Thus, the compliance action or inaction ("decline to pursue") with respect to the performance of an entity against the stated requirements in the standard is a matter of the CMEP and should not be addressed through the standards interpretations process. Compliance activity should be based on the facts and circumstances of each case measured against the performance requirements of the standard. Standards (including interpretations) are for describing the behaviors and actions of registered entities necessary for the reliable planning and operation of the bulk power system not the Compliance Enforcement Authority. Informed and expert discretion rather than this interpretation (which requires inaction) is a better answer for the Reliability Assurer. Further, ALR 2-5 has a stated purpose as a measure of how much risk a system is exposed to for extreme or unusual contingencies (Simultaneous Contingencies - Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation). The results of ALR 2-5 are expected to help validate current contingency reserve requirements and document how often these “extreme or unusual” contingencies occur. These activities should

Organization	Yes or No	Question 1 Comment
		continue.
Response: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Prior to penalties and sanctions under Section 215, the consequence of failing DCS was to require an increase in contingency reserves. This is the “compliance evaluation” referred to under Section D. Thus, the concept of “most severe single contingency” (MSSC) as a criterion against which to require additional contingency reserve was employed and for large contingencies may require more time to respond. This is not correct. MSSC was used to recognize the fact that the Reserve obligation was to include not simply the largest “generator” but that the largest common mode failure must also be covered. That included single interchange schedules that could be curtailed instantaneously. However, MSSC varies as a function of the assets operating at any given time. Thus the MSSC may be 1500 when a BA’s 1500 MW nuclear unit is running, but then becomes 500 when that nuclear unit is off, and the BAs next largest unit is a 500 MW generator. The time response was not addressed in the NWPP question or in the interpretation. The question NWPP asked was what is excluded from compliance penalty by the DCS standard. It is clear that the standard held BAs to meet the DCS requirement when they had a contingency. It is also clear that contingencies less than 80% of the MSSC were not mandated to be “reported”. The drafters of the standard did not intend that contingencies below 80% did not require action, but the consequence of the non-reporting exception provided that situation. ALR 2.5 is not in question. What NWPP asked was if there are two contingencies at the same time, does the standard relieve them of the responsibility to respond in the given time frame. To paraphrase the IDT response, “if a BA experiences two simultaneous contingencies who total output was greater than the BAs MSSC, the BA must respond but will not be responsible to comply with the strictures of the requirement.” SERC’s contention regarding the Reliability Assurer may or may not be true, but the IDT is tasked with interpreting what the standard		

Organization	Yes or No	Question 1 Comment
in question says. SERC is welcome to submit a SAR to change the standard.		
ReliabilityFirst	No	ReliabilityFirst votes in the Negative for the Interpretation of BAL-002 since ReliabilityFirst believes the drafted interpretation to Question 1 incorrectly expands on the language in Requirement R4 and incorrectly attempts to explain how to comply with the Requirement. If a reportable disturbance occurs (i.e. contingencies that are greater than or equal to 80% of the most severe single Contingency) and is greater than the most severe single Contingency, ReliabilityFirst questions why an entity would not be required to meet the Disturbance Recovery Criterion. Nowhere within the requirements are there exceptions for Reportable Disturbance greater than the most severe single Contingency. Based on R4, the applicable entity “...shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances”. For example, if an entity failed to meet the meet the Disturbance Recovery Criterion for a disturbance equaling 110% of their most severe single Contingency, they would potentially be found non-compliant. In addition, ReliabilityFirst does not believe the quasi definition of “Simultaneous Contingencies” within the “Additional Compliance Information” is not enforceable since it is not a Reliability Requirement, and is not even a NERC Defined term.
Response: Regarding RFC’s concern about expanding the language of the requirement, the IDT refers them to the IDT’s response to AEC Inc. An IDT is not formed to respond to why a standard mandates what it mandated; the IDT is only obligated to interpret what the drafters meant by the mandated requirement.		

Organization	Yes or No	Question 1 Comment
Regarding Excludable Disturbances RFC is correct that exclusions are not in the requirement, but as explained in the AEC Inc response the IDT was permitted to use other reference material. RFC is referred to the cited reference (Performance Standards Reference Guidelines - http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf) Reporting Section items a.2. And a.3. That specifically references Excludable Disturbances. According to the requirement and the associated reference materials the IDT concludes that a BA cannot be held non-compliant with a disturbance that is 110% of their MSSC. The standard specially excludes such disturbances from compliance. Regarding Simultaneous Contingencies, the IDT would simply refer to the BOT allowance for the IDT to include such reference material.		
LG&E and KU Services Company	No	The IDT's explanation of MSSC may be unnecessary and confusing, especially statements such as: "MSSC is a variable that the BA knows and operates to in real time." "Thus the BA knows its MSSC which can vary from hour to hour and minute to minute." "To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC)." "In the absence of an identifiable/specific reason, which is recognized by the BA in advance, the real-time MSSC should not exceed the prospective MSSC. Unless such an abnormal situation exists, all evaluations of DCS compliance must be based on the prospective MSSC value. The IDT needs to be very clear with any language suggesting that the real-time MSSC can exceed the planned/recognized/"prospective" MSSC. If a disturbance exceeds the planned/recognized/"prospective" MSSC value, it is outside the definition of MSSC and should not be subject to compliance evaluation. The requirement for a prospective MSSC is for the MSSC be used for planning purposes, not for real-time operations, even though it is

Organization	Yes or No	Question 1 Comment
		used in such operations. MSSC is not a defined term in the NERC Glossary but work is in progress under NERC Project 2010-14.1 to develop a definition of MSSC. Therefore, it would not be in the best interest of the IDT in providing this interpretation to attempt to describe or define MSSC. LGE and KU Services recommends all language related to the IDT's explanation of MSSC be deleted from Response 1. Also, the language explaining the "Compliance and reporting category" and "Reporting only category" appears to be outside the inquiry of Question 1 and is suggested for deletion. LGE and KU Services suggests Response 1 be reduced to simply the first sentence of the response as it clearly answers Question 1: "The IDT agrees that the Disturbance would be excluded from compliance."
Response: Thank you, the IDT agrees that it is necessary to be "very clear", hence the explanation. To use the proposed straight forward answer would leave others asking what is meant. Since your answer and our answer agree, the IDT will retain the explanation.		
Electric Reliability Council of Texas, Inc.	No	ERCOT agrees with the SRC comments. However, in addition to the SRC comments, ERCOT offers the following: ERCOT does not agree with additional details in the section that attempts to provide clarification. See the two excerpts below: Quote from Additional Compliance Information section: "To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC). An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition." There should be a period after the word "reported" and the phrase "to allow the ERO to help ensure

Organization	Yes or No	Question 1 Comment
		that it is not a continuing condition.” should be struck and removed. Quote from Additional Compliance Information section: “The Reporting only category is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC.”The entire last sentence should be struck and removed. BA’s are the functional entities responsible for coordinating with RC’s, other BAs, TOPs, and GOPs to determine if a common mode failure requires a different MSSC. The ERO (NERC) is an oversight entity responsible for developing reliability standards and monitoring and enforcing compliance with those standards. It is not a functional entity. As such, it has no role in functional responsibilities, including the establishment of single contingencies and operating to respect such contingencies in accordance to the applicable NERC standards and requirements. Accordingly, it is inappropriate for the interpretation to suggest, either directly or indirectly, that the ERO is in a position to monitor contingencies on the system, common mode or otherwise, to determine if such reoccurrences warrant consideration of multiple contingencies as a single contingency that could serve as an areas MSCC. There is explicit language in the interpretation that places the ERO in this role. Because this exceeds the scope of the ERO’s functions and authority the interpretation must be revised to remove the problematic language. The above revisions are intended to address this issue, and ERCOT respectfully suggests the SDT make the suggested deletions.
Response: The IDT is responsible to interpret what the requirement meant. The idea of having a requirement for reporting excludable disturbances just for the sake of reporting does not make sense. The reason for reporting was to ensure that reliability entities do not take advantage of the exclusion. At the time the standard was written the NERC Performance Subcommittee		

Organization	Yes or No	Question 1 Comment
(translated here to be the ERO) was to collect and evaluate those instances.		
ISO-RTO Standards Review Committee	Yes	We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below: "Most Severe Single Contingency (MSSC) - this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction." We do not agree the term "firm transaction". The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA's resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction. Further, the term "firm transaction" is subject to debate as to whether the firmness is in the energy component or in the transmission service component. If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word "firm" from the clarification section.
Response: Thank you for your affirmative response and clarifying comment.		
ACES Power Marketing Standards Collaborators	Yes	We conceptually agree with the position of the interpretation. However, we believe that the current response expands issues that were not raised in the original question. One example is that the "MSSC value at any given time may be more or less than the annually identified prospective MSSC" is

Organization	Yes or No	Question 1 Comment
		contradictory to the interpretation. How could the MSSC value could ever be higher than the list of candidate MSSCs identified in the annual review. Also, in the “reporting only” category in response 1, the IDT incorrectly characterizes that the ERO would have authority or the information to alert the BA that two (or more) contingencies must be considered as a single event and thus considered as the MSSC. The ERO does not determine the MSSC, the BA or RSG makes that determination. For simplicity and clarity, we recommend that the interpretation state: Disturbances greater than MSSC are excluded from the compliance calculation, based on the additional compliance information section of BAL-002-0. The IDT could strike everything following this statement from the interpretation and would convey the same message in a more clear and concise manner.
Response: Thank you for your affirmative response and clarifying comment. An MSSC can be higher if the BA expanded its boundaries, or if the BA made an interchange schedule larger than expected.		
El Paso Electric	Yes	El Paso Electric (EPE) generally supports the first interpretation proposed by the IDT but is concerned with the language immediately following "To be clear..." because it does not acknowledge the fact that many BAs have placed responsibility in the hands of a RSG. The interpretation states that "...a BA is responsible for the MSSC at all times...". EPE believes that this responsibility should be shared with a RSG, where appropriate. EPE would be more comfortable with an interpretation that read "To be clear a BA or RSG, as applicable, is responsible for the MSSC at all times..."
Response: The issue in question depends on the type of RSG involved. The BA is responsible. However, if a BA makes use of an RSG then based on the rules of the RSG it could be the BA, it could be the RSG or it could be some combination. The IDT believes that its response properly allows for any of the above. Based on the governance of the RSG and the Region it is in.		
Duke Energy	Yes	We suggest that there should be a SAR to define the terms MSSC and

Organization	Yes or No	Question 1 Comment
		"excludable disturbance" add them to the NERC Glossary.
Response: Thank you for your affirmative response and clarifying comment. There –presently is a project under development to address the issue you have brought forward (Project 2010-14.1 BARC – Reserves).		
SPP Standards Review Group	Yes	This interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
SERC Operating Committee Standards Review Team	Yes	The SERC OC Standards Review Group gladly presents the following comments. The SERC OC Standards Review Group agrees only with the interpretation portion of the response. The Group strongly disagrees there is a need for the additional explanation of the interpretation. The explanation presents more confusion and questions around the Standard. The simple interpretation is very clear and concise.
Response: Thank you for your affirmative response and clarifying comment.		
Independent Electricity System Operator	Yes	We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below:"Most Severe Single Contingency (MSSC) - this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction."We do not agree the term "firm transaction". The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA's resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction.

Organization	Yes or No	Question 1 Comment
		Further, the term “firm transaction” is subject to debate as to whether the firmness is in the energy component or in the transmission service component. If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word “firm” from the clarification section.
Response: Thank you for your affirmative response and clarifying comment. See our response to SRC.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
Exelon Corporation	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Yes	
Entergy Services, Inc.	Yes	

2. Do you agree with Response 2 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation the majority felt that the terms “pre-acknowledged RSGs” and “dynamically allocated RSGs” were not defined and therefore should not be used. The IDT explained that the terms “pre-acknowledged” and “dynamic” were used in the common English terms to be an RSG that is “recognized ahead of time rather than an after-the-fact”. And an RSG that is used on an on-call basis and thus its responding members are “not static”, respectively.

A few responders questioned why the rules were different. The IDT explained that a “pre-acknowledged RSG” knows who is participating and who is not. However, a “dynamically allocated RSG” operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate.

Organization	Yes or No	Question 2 Comment
Duke Energy	No	It's not clear what the drafting team is saying, particularly the reference to “dynamic allocation of membership”. What's the difference between pre-acknowledged RSGs and dynamically allocated RSGs, and why are the exclusion rules different?
Response: RSG as it pertains to structure is not a common entity. Some RSG are designed to be “on-call” and hence have a dynamic membership. The aforementioned RSG could consist of a pool of 20 BAs, but have 2 (of 20) members who are responding for one disturbance and 15 (of 20) for the next. While the pool of BAs may be fixed, based on the governance of the particular RSG, the obligations of the RSG are allocated only to those who agree to participate for the given disturbance. Of course other RSGs may operate as a unit for all disturbances that occur and thus all pool members are obligated for all disturbances (in effect they become a single BA for purposed of DCS).		

Organization	Yes or No	Question 2 Comment
The exclusion is really the same, what is different is in deciding who is to be counted in multiple disturbances (note this difference is small since the probability of one BA in an RSG having a disturbance at the same as another BA having an independent disturbance is low). But the fact remains that weather conditions could and do span multiple BAs and can result in such simultaneous disturbances (although it is more likely that one BA would be more likely to experience such independent disturbances.) For a pre-acknowledge RSG, one knows exactly who is participating and who is not. In an RSG that operates only on an on-call basis (i.e. a dynamically-allocated RSG) one cannot determine who is responsible and who is not UNTIL everyone who wants to participate has communicated their participation.)		
SERC Operating Committee Standards Review Team	No	The SERC OC Standards Review Group feels the interpretation and clarification are both very confusing, thus raising numerous other questions. The use of the words “pre-acknowledged RSGS” and “dynamic allocated RSGS” appear to be new terms introduced in the response. Also, a reference to a Technical Document is made in the response. The Group is unsure of what Technical Document the IDT is referring. Nor does the Group understand if such reference to the Technical Document is an agreement with such document by the IDT or if the Technical Document is referenced as to be included in the response and subject to being opened and the processes and procedures of such document being made part of a compliance audit.
Response: The Technical document can be found at the following link. http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf The BOT recognized that the creation of DCS was supported by other materials such as Reference Documents and a Frequently Asked Questions. These documents hold the key to what was meant by the DCS requirements and are important in any interpretation.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided. For example, it is not clear to us exactly what “pre-acknowledged” or “dynamic” means in regards to Reserve Sharing Groups. These terms are not found anywhere within the standard itself, nor are they commonly used to describe or qualify Reserve Sharing Groups.

Organization	Yes or No	Question 2 Comment
Response: The terms “pre-acknowledged” and “dynamic” are used in the common English terms to be an RSG that is “recognized ahead of time rather than after-the-fact”, and an RSG that is used on an on-call basis and thus its responding members are “not static”, respectively.		
SERC	No	See answer to question #1.
Response: See response to Question #1		
LG&E and KU Services Company	No	The meaning and use of the adjectives “pre-acknowledged” and “dynamically allocated” in description of RSG in Response 2 seem to be unnecessary, confusing and beyond the scope of Question 2. As stated in Response 2, there is a NERC Glossary definition of RSG and that is the subject of Question 2 - not the applicability of R5 to organizational variations of RSGs. The IDT has referenced a “Technical Document” that has not been included in the posting. The content therefore of the Technical Document is unknown. LGE and KU Services suggests Response 2 be reduced to only the language used in the “In summary,....” portion of the response as it clearly answers Question 2, edited as follows: "The Standard was written to provide RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period."
Response: Question 2 is about exclusions for RSGs. The reference material (http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf) makes the distinction about whether or not the Region agrees ahead of time (pre-acknowledged) or whether or not there is an known MSSC for the RSG (if the responders are dynamically joining or not). Thank-you for your suggestion, but given the responses to the interpretation, the IDT will retain the explanation.		

Organization	Yes or No	Question 2 Comment
ACES Power Marketing Standards Collaborators	Yes	We largely agree with the interpretation. However, we want to point out that the concept of pre-acknowledged RSGs have disincentivized Adjacent Balancing Authorities (not in a pre-acknowledged RSG) to provide reserves in less than 10 minutes even if they are capable. If an Adjacent Balancing Authority provides emergency energy in an amount that exceeds its own MSSC with a ramp less than 10 minutes and fails to recover its ACE from within 15 minute of the initial disturbance, the Adjacent BA may be found non-compliant despite the fact the it provided the appropriate reliability assistance. Compliance should not disincentivize actions that ensure reliability.
Response: The IDT agrees that the terms of an agreement may influence a BA on agreeing to participate in a given type of RSG. But the responsibility and allocation of penalties is a governance matter defined with the dictates of the agreement the BA signs, it is not a matter for the requirement. This interpretation neither incents or dis-incents making an agreement of any kind. If an entity does not agree with the rules of a proposed RSG agreement they are not obligated by this interpretation to sign that agreement.		
El Paso Electric	Yes	EPE generally supports the second interpretation by the IDT but requests that IDT clarify the scope of compliance evaluations for BAs who are part of a RSG and experienced a reportable event, without regard to whether any individual BA member of the RSG requested assistance. If a RSG determines that the group as a whole complied with CPS then there should be no need for any individual BA review or reporting under R5, without regard to whether the BA called for reserve activation from other RSG members, or not. The interpretation should include this clarification.
Response: This interpretation is based on the concept that BAs would submit “Reportable Disturbances”. These reports provide more than compliance information, they provide information on the state of responses. This information was deemed valuable to the Resources Subcommittee. Even in today’s environment there is a need to “self-report” non-compliance. The question raised by the NWPP is for a situation in which a BA is non-compliant with the DCS requirement but because of circumstances (explained in the Reference documents and in the Interpretation), the BA is excused from complying with the requirement (i.e. the disturbance is excludable). The decision for		

Organization	Yes or No	Question 2 Comment
exclusion should be easy but as indicated by some responses there are CEAs who say they would hold entities non-compliant for such events.		
SPP Standards Review Group	Yes	Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the SRC comments.
Response: Thank you for your affirmative response and clarifying comment.		
Associated Electric Cooperative Inc - JRO00088	Yes	Rationale: In our opinion, the IDT failed to answer Question #2, which could have been answered with a simple “Yes”. Instead, they appear to attempt legislating upon particulars of how all RSGs should structure portions of their policies under R2, by again referring to the concept of “dynamic membership”. Our understanding is that such expansion of Standard governance can only be done under SDT effort and subsequent industry approval through the ballot process. (See AECI’s earlier response to Question 1 above.)
Response: Thank you for your affirmative response and clarifying comment.		
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Entergy Services, Inc.	Yes	
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
ReliabilityFirst	Yes	
Exelon Corporation	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
ISO-RTO Standards Review Committee	Yes	

3. Do you agree with Response 3 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation the majority questioned which version of the BAL-002 (BAL-002-0 or BAL-002-1) this interpretation would apply to. The IDT explained that although the interpretation was requested for BAL-002-0 it would apply to BAL-002-1 as well.

A few responders objected to the wordiness of the response. The IDT explained that their intent was to encourage an understanding of the interpretation. The first two paragraphs were basically a restatement of the requirement and the last paragraph was the actual interpretation.

Organization	Yes or No	Question 3 Comment
Duke Energy	No	It's not clear what the drafting team is saying. Does "excluded from compliance evaluation" mean that R4 does not apply to Disturbances that exceed the MSSC for a BA or RSG? Does it matter if the RSG is pre-acknowledged or dynamically allocated? The drafting team's response to Question 2 seems to indicate that it does matter. We agree that DCS is not applicable for losses greater than the MSSC, and also that DCS compliance is not required for losses less than 80% of the MSSC (or lower if a lower threshold is adopted for DCS reporting). This interpretation is performed on BAL-002-0, but the current effective standard is BAL-002-1 as of 4-1-2012. If the interpretation is approved, what is its applicability to BAL-002-1? Under BAL-002-0 the default Disturbance Recovery Period could be adjusted to better suit the needs of an Interconnection (R4.2) and the default Contingency Reserve Restoration Period could be adjusted to better suit the reliability targets of the Interconnection (R6.2), both based on analysis approved by the NERC Operating Committee. This has been deleted from both requirements in BAL-002-1.

Organization	Yes or No	Question 3 Comment
Response: The IDT believes the interpretation is clear and that the Interpretation would apply to the current version as well as to the former version.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.
Response: See response to Question #1.		
SERC	No	See Response to question #1.
Response: See response to Question #1		
Exelon Corporation	No	Response 3 of the interpretation that requests clarification on the phrase “excluded from compliance evaluation” could be clearer. The first portion of the response gives the impression that the IDT is of the opinion that the obligation to comply with the DCS extends to events larger in magnitude than the MSSC. The paragraphs that follow go on to clarify that an event greater than the MSSC would not be required to recover ACE within 15 minutes, making compliance with the DCS not mandated in these instances. The latter (disturbances exceeding the MSSC being excluded from DCS compliance and 15 minute recovery) is consistent with practice and in line with the interpretation indicated by the NWPP. In order to more fully clarify the interpretation, the IDT should make clear that compliance with the DCS is not mandated for disturbances exceeding the MSSC.
Response: The first two paragraphs are meant as a restatement of the requirements. The last paragraph is the interpretation.		
ISO-RTO Standards Review Committee	Yes	It might be clearer if the reponse added the phrase [of the Disturbance Control Standard] after “loss shall be reported, but excluded from compliance evaluation”.

Organization	Yes or No	Question 3 Comment
		Following a large event, the BA would still be accountable for other standards (e.g. IRO standards)
Response: Thank you for your affirmative response and clarifying comment.		
ACES Power Marketing Standards Collaborators	Yes	We agree for the most part with this interpretation. However, we do have a few points we would like to address. We recommend striking the entire second paragraph because it is irrelevant. The standard does not say comply with DCS “for every reportable disturbance.” The key is whether a BA is required to recover ACE within 15 minutes for contingencies greater than MSSC, and that answer is no. The IDT should keep the interpretation simple. A recommendation for wording the interpretation: A BA is not required to recover ACE within 15 minutes for contingencies greater than MSSC, as stated in section 1.4 (“Additional Compliance Information”). We recommend that the IDT reduce the amount detail in the rationale and focus on the three questions in the request. The current draft of the interpretation is wordy, confusing and provides excessive details instead of answering the questions that were asked. Also, the IDT did not state that this interpretation would apply to BAL-002-1, which has been enforceable since 4/1/2012. If NERC is going to continue with the interpretation process for BAL-002, the interpretation should apply to both versions of the standard. Finally, we encourage NERC to consolidate standard projects. There are currently 10 standard projects under development for BAL standards. NERC should consider either a consolidation to a reduced amount of BAL projects or even a single project to cover all BAL issues in order to avoid duplication, overlap, inefficient use of resources and confusion.
Response: Thank you for your affirmative response and clarifying comment. The wordy explanation was meant to encourage an understanding of the interpretation. Given the overwhelming support that approach seems to have been effective.		

Organization	Yes or No	Question 3 Comment
The Interpretation would apply to the current version as well as to the former version. This is an interpretation not a standard development. There is a need to respond to this issue as soon as possible. The BAL project may or may not receive approval and to link that Project with this Interpretation would not be helpful to those waiting for this interpretation.		
Associated Electric Cooperative Inc - JRO00088	Yes	We agree with this summary determination. In addition, the August 2, 2006 NERC BOT approved, and subsequently FERC accepted Glossary definition for Reportable Disturbance clearly specified that the definition “not be retroactively adjusted in response to observed performance”, adding weight to this drafting-team’s response to Question 3. (FERC_Filing_Proposed_Reliability_Standards_Docket_RM06-16-000.pdf)
Response: Thank you for your affirmative response and clarifying comment.		
SPP Standards Review Group	Yes	Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Independent Electricity System Operator	Yes	(1) We generally agree with the proposed interpretation. However, we are not sure if this request fits well into NERC’s criteria for acceptance as a valid request since it appears that the requester asks specifically on the compliance implications and compliance elements. We suggest the interpretation drafting team (IDT) to evaluate whether or not the request is a valid one that seeks clarity on the requirements, rather than on the compliance aspects of the standard/requirements. If the IDT does assess that the questions are addressing a compliance issue, then we suggest the IDT to bring this to the attention of the Standards Committee for a determination of the appropriate means to address the questions.

Organization	Yes or No	Question 3 Comment
		(2) The IESO agrees with NERC's interpretation of BAL-002. However, we believe additional discussion and thought need to be applied to other Standards to ensure that no gaps or overlaps exist in both task execution and Standard application. Different Standards obligate Reliability Entities to fulfill certain tasks as it pertains to balancing: conditions. This includes: - o BAL- 002 outlines obligations to balance following Reportable Disturbances; - o EOP-002 outlines obligations to balance during Capacity and Energy Emergencies; and - o TOP-001 outlines obligations to balance during System Emergencies. All of these Standards have similarities but need interpretation to ensure consistent application. These interpretations are based on an understanding of the NERC Functional Model and upon clear statements in the purpose and requirement sections in the Standards. We believe that the objective of each of the Standards list above must be clarified to reduce confusion and support consistent application.
Response: Thank you for your affirmative response and clarifying comment. The IDT is not making a decision on a given compliance issue, it is simply providing an interpretation of what is meant by excludable disturbances. It is not within the purview of an IDT to address other issues outside the bounds of the proposed question. The IESO is encouraged to participate in Projects that address the above requirements or to submit a SAR to rectify their issues and concerns.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		

Organization	Yes or No	Question 3 Comment
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the SRC comments.
Response: Thank you for your affirmative response and clarifying comment.		
SERC Operating Committee Standards Review Team	Yes	NONE
El Paso Electric	Yes	No Comment.
Bonneville Power Administration	Yes	BPA is in support of BAL-002-0 Interpretation and has no comments or concerns at this time.
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
LG&E and KU Services Company	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 3 Comment
Entergy Services, Inc.	Yes	
ReliabilityFirst		ReliabilityFirst disagrees with the drafted interpretation. Regardless of the references to outside sources (the reserve requirement specified in R3.1 of BAL-002-0, the text of Section 1.4 of Part D of BAL-002-0, and the documented history of the development of BAL-002-0), compliance is to be assessed on a requirement by requirement basis. Requirement R4 requires that an applicable entity "...shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances". Clearly, there is no exception listed within the requirements for Reportable Disturbances greater than the most severe single Contingency.
Response: The IDT disagrees with your perception. In addition, the industry ballot indicates that the Industry does not agree with RFC's perception.		

END OF REPORT

Exhibit C

Summary of the Interpretation Development Proceedings and Record of Development of
Proposed Interpretation

Exhibit C

I. SUMMARY OF THE INTERPRETATION DEVELOPMENT PROCEEDINGS

The development record for the interpretation of BAL-002-1 is summarized below.

Exhibit C contains the complete record of development for the proposed standards.

a. Overview of the Interpretation Drafting Team

When evaluating proposed Reliability Standard, the Commission is expected to give “due weight” to the technical expertise of the ERO.¹ The technical expertise of the ERO is derived from the drafting team. For this project, the interpretation drafting team consisted of four industry experts with over 125 years of collective experience. Drafting Team members included Howard Illian of Energy Mark, Inc., who has published a variety of papers on the subject of Frequency Response, including a 2010 report that was funded by the FERC, Office of Electric Reliability,² and included a diversity of experience from both the continental United States and Canada. Each individual is considered to be an expert in his field. A detailed set of biographical information for each of the team members is included along with the interpretation drafting team roster in **Exhibit D**.

b. The First Posting and Initial Ballot

Project 2009-19—Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group was initiated on September 2, 2009 by the Northwest Power Pool Reserve Sharing Group as a request for an interpretation of Requirements R4 and R5 of BAL-002-0. The first draft of the interpretation of BAL-002-0 was posted for a pre-ballot review from January 15, 2010 to

¹ Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824o(d)(2) (2011).

² See e.g., Illian, H. (2010). *Frequency Control Performance Measurement and Requirements*, LBNL-2145E, Ernest Orlando Lawrence Berkeley National Laboratory; available at: <http://www.ferc.gov/eventcalendar/Files/20110120114346-Frequency-Control-Performance-Measurement-and-Requirements.pdf>; Eto, J. H., Undrill, J., Mackin, P., Daschmans, R., Williams, B., Illian, H., et al. (2010). *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation*. LBNL-4142E. Ernest Orlando Lawrence Berkeley National Laboratory; available at: <http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf>.

February 15, 2010. The draft interpretation was then posted for an initial ballot from February 15, 2010 to February 26, 2010.

The Balancing Authority Controls standard drafting team was originally assigned to provide a response to the interpretation request. This standard drafting team developed a response using only the information within the requirements of the standard and the interpretation received only a 48.60% approval rating. The standard drafting team determined that any further interpretation could not be developed unless the team could consider measures and the additional compliance elements of the standard.

c. Level 1 Appeal

On January 17, 2012, NERC received a Level 1 Appeal for inaction from the Standards Review Committee (“SRC”) of the ISO/RTO Council on Project 2009-19 in accordance with the NERC Standard Processes Manual. The appellants asked for clarity on the following issues:

- Did NERC, or the Standards Committee, convene the IDT, after comments were received. What industry and/or NERC personnel made up the IDT?
- What accounted for the Standards Committee placing the RFI on hold (in October 2010) and the delay in processing the RFI prior to the Standards Committee 2011 action to place on hold pending Interpretations?
- Do the Standards Committee Agendas correctly indicate that NERC considered the RFI an invalid request, and if so, why?

As part of the appeal process, NERC’s Vice President and Director of Standard and Training issued a data request to the NERC Standards staff involved in the development of the interpretation. On March 28, 2012, NERC’s Vice President and Director of Standards and Training formally responded to the appeal in a letter addressed to the Chairman of the ISO/RTO

Council SRC. The NERC staff response to the data request was included with the letter.³ NERC concluded that the appeal could not be substantiated based on the evidence presented by NERC staff in the data response. NERC found that although there was an initial delay in action during which the policy and practices for handling interpretations were being modified by the NERC Board of Trustees and the Standards Committee, NERC staff did in fact take action. NERC created an interpretation drafting team in response to the RFI, conducted an industry ballot, and ultimately deemed the RFI ineligible for the formation of an interpretation under the newly modified rules for developing interpretations.

However, in May 2012, NERC staff presented the issue of whether interpretations can be developed based on language outside of Requirements to the Board of Trustees Standards Oversight and Technology Committee (“SOTC”) for consideration. The SOTC determined at that meeting that interpretations may be developed using any language in the standard, including compliance related sections. The minutes from that meeting reflect the discussion as follows:

Need for Relief from Interpretation Policy – BAL-002

Mr. Herb Schrayshuen, vice president and director of standards and training provided an overview of the issues regarding the BAL-002 interpretation. After significant discussion the committee rejected the approach of a onetime waiver in favor of addressing the issue on a policy level more comprehensively. The conclusion is that strict construction for the purposes of interpretation was never meant to limit the materials considered in developing the interpretation solely to the contents of the requirements in a standard, but can include any language in the standard, including compliance related sections.

Following this determination by the SOTC, the Standards Committee appointed a new interpretation drafting team.

d. The Second Posting – Formal Comment and Successive Ballot

³ The NERC letter and data response can be found at http://www.nerc.com/docs/standards/sar/Reply-IRC-Level_1_Appeal_BAL-002_03-28-2012.pdf (Letter) and http://www.nerc.com/docs/standards/sar/IRC_Level_1_Appeal_of_BAL-002RFI-DataRequestandExhibits.pdf (Data Response).

The second draft of the interpretation was posted for a 45-day formal comment period from July 25, 2012 to September 4, 2012. Twenty-five sets of comment were received from ninety-six different individuals from approximately fifty-six companies representing eight of the ten NERC industry segments. The interpretation drafting team did not make changes to the interpretation in response to comments. A minority of commenters expressed concerns with certain parts of the proposed interpretation. These concerns are summarized below.

- Of the commenters that expressed concerns with the interpretation, a number questioned the use of the “Additional Compliance Information” in providing an interpretation of the requirements. The interpretation drafting team explained that the NERC BOT specifically allowed the use of the reference materials in developing this interpretation. The interpretation drafting team further explained that the NERC BOT recognized that in the conversion of NERC Policies to Version 0 standards, critical information was placed in sections outside of the requirements themselves and that strict construction policy in the case of the DCS standard was not consistent with the standard itself.
- Several responders questioned how a Reserve Sharing Group (“RSG”) was to respond and the amount of time allowed to respond. The interpretation drafting team explained that the clarification requested by NWPP was not about how an RSG was to respond or the amount of time allowed but instead focused on under what conditions could a Disturbance be excluded for compliance evaluation
- Several responders noted that the terms “pre-acknowledged RSGs” and “dynamically allocated RSGs” were not defined and therefore should not be used. The interpretation drafting team explained that the terms “pre-acknowledged” and “dynamic” were used in the common English terms to be an RSG that is “recognized ahead of time rather than an after-the-fact.” And an RSG that is used on an on-call basis and thus its responding members are “not static,” respectively.
- A few responders questioned why the rules were different for an RSG. The interpretation drafting team explained that a “pre-acknowledged RSG” knows who is participating and who is not. However, a “dynamically allocated RSG” operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate.
- A few responders questioned which version of the BAL-002 (BAL-002-0 or BAL-002-1) this interpretation would apply to. The IDT explained that although the interpretation was requested for BAL-002-0 it would apply to BAL-002-1 as well.

A successive ballot was held from August 23, 2012 to September 4, 2012. The proposed interpretation achieved a quorum of 79.21% and an approval of 87.78%.

e. Third Posting – Recirculation Ballot

A recirculation ballot of the interpretation to BAL-002-0 was conducted from September 28, 2012 to October 8, 2012. The interpretation achieved a quorum of 85.11% and an approval of 90.34% and was therefore deemed to be approved by the industry.

f. Board of Trustees Approval of Interpretation

The final draft of the interpretation was presented to the NERC Board of Trustees on November 7, 2012. NERC staff provided a summary of the interpretation, as well as a summary of minority issues and associated drafting team responses. The NERC Board of Trustees approved the interpretation, and NERC staff recommended that the interpretation be filed with applicable regulatory authorities.

Project 2009-19

Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group

Status:

The interpretation was adopted by the NERC Board of Trustees on November 7, 2012, and is pending regulatory approval.

Summary:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

1. although a Disturbance^{1[1]} that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
2. with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and
3. the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

^{1[1]} Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Purpose / Industry Need:

In accordance with the Reliability Standards Development Procedure, the interpretation must be posted for a 30-day pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

Appeal:

On January 17, 2012 NERC received a Level 1 Appeal for inaction from the ISO/RTO Council's Standards Review Committee on Project 2009-19 - Northwest Power Pool's Reserve Sharing Group's request for an interpretation of BAL-002-0, Requirement R4. The appellants asked for clarity on the following issues:

- Did NERC, or the Standards Committee, convene the IDT, after comments were received. What industry and/or NERC personnel made up the IDT?
- What accounted for the Standards Committee placing the RFI on hold (in October 2010) and the delay in processing the RFI prior to the Standards Committee 2011 action to place on hold pending Interpretations?'
- Do the Standards Committee Agendas correctly indicate that NERC considered the RFI an invalid request, and if so, why?

[IRC Appeal](#)

[Data Information Request and Exhibits](#)

[NERC Response](#)

Draft	Action	Dates	Results	Consideration of Comments
Draft 2 Northwest Power Pool RSG BAL-002-0 Interpretation (16) Request for Interpretation (17)	Recirculation Ballot Info (18) Vote>>	09/28/12 - 10/08/12	Summary (19) Full Record (20)	
Draft 2 Northwest Power Pool RSG BAL-002-0 Interpretation (7) Request for Interpretation (8) Supporting Documents: Unofficial Comment Form (Word) (9)	Successive Ballot Updated Info (10) Info (11) Vote>>	08/23/12 - 09/04/12 (closed)	Summary (12) Full Record (13)	
	Formal Comment	07/25/12 - 09/04/12	Comments Received (14)	Consideration of Comments (15)

	Submit Comments>>	(closed)		
	Join Ballot Pool>>	07/25/12 - 08/23/12 (closed)		
Draft 1 Northwest Power Pool RSG BAL-002-0 Request for Interpretation (1) Interpretation (2)	Initial Ballot Info (3) Vote>>	02/15/10 - 02/26/10 (closed)	Summary (5) Full Record (6)	
	Pre-ballot Review Info (4) Join>>	01/15/10 - 02/15/10 (closed)		

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard	
Date submitted:	September 2, 2009
Date accepted:	September 2, 2009
Contact information for person requesting the interpretation:	
Name:	Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization:	Northwest Power Pool Reserve Sharing Group
Telephone:	503-445-1074
E-mail:	jerry.rust@nwpp.org
Identify the standard that needs clarification:	
Standard Number (include version number):	BAL-002-0
Standard Title:	Disturbance Control Performance
Identify specifically what requirement needs clarification:	
<u>Requirement Number and Text of Requirement:</u>	
B. Requirements	
* * *	
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	
R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value. R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.	
* * *	
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. * * * Compliance may be demonstrated by either	

of the following two methods:

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

D. Compliance

1.4 Additional Compliance Information

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Clarification needed:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

- (1) although a Disturbance¹ that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
- (2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve

¹ Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

- (3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for “enough Contingency Reserve to cover the most severe single Contingency”) meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute “Reportable Disturbances.” See Section 1.4 of Part D of BAL-002-0 (where the “Additional Compliance Information” includes a definition of “Reportable Disturbance”).

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (see, e.g., Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that “An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.”)

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard	
Date submitted:	September 2, 2009
Date accepted:	September 2, 2009
Contact information for person requesting the interpretation:	
Name:	Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization:	Northwest Power Pool Reserve Sharing Group
Telephone:	503-445-1074
E-mail:	jerry.rust@nwpp.org
Identify the standard that needs clarification:	
Standard Number (include version number):	BAL-002-0
Standard Title:	Disturbance Control Performance
Identify specifically what requirement needs clarification:	
<u>Requirement Number and Text of Requirement:</u>	
B. Requirements	

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	
R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.	
R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.	

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. *** Compliance may be demonstrated by either of the following two methods:	

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

D. Compliance

1.4 Additional Compliance Information

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Clarification needed:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

- (1) although a Disturbance¹ that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
- (2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

¹ Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

- (3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for “enough Contingency Reserve to cover the most severe single Contingency”) meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute “Reportable Disturbances.” See Section 1.4 of Part D of BAL-002-0 (where the “Additional Compliance Information” includes a definition of “Reportable Disturbance”).

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (see, e.g., Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that “An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.”)

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Project 2009-19: Response to Request for an Interpretation of BAL-002-0 for the Northwest Power Pool Reserve Sharing Group

The following interpretation of standard BAL-002-0 — Disturbance Control Performance, Requirements R4 and R5, was developed by several industry experts selected by NERC based on their knowledge of the subject matter.

Requirement Number and Text of Requirement

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1 A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

D. Compliance

1.4 Additional Compliance Information

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The

Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Question 1:

Although a Disturbance² that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?

Response 1:

The BAL-002-0 Reliability Standard does not grant an exclusion from compliance evaluation for all Disturbances that exceed the most severe single Contingency. The standard excludes from compliance evaluation specific Disturbances. Simultaneous Contingencies that have a combined magnitude in excess of that of the most severe single Contingency are excluded from compliance evaluation. Subsequent contingencies following an initial Reportable Disturbance that occur more than one minute after the start of the Reportable Disturbance but within the Reportable Disturbance Period can be excluded from compliance evaluation; however, the initial Reportable Disturbance is not excluded from compliance evaluation.

Question 2:

With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?

Response 2:

As discussed in the response to Question 1, the exclusion from compliance evaluation does not apply to all Disturbances with combined magnitudes exceeding the most severe single Contingency.

As described in Requirement R5, the Reserve Sharing Group in its entirety is “considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members.” Therefore, the “exclusion from compliance evaluation” would apply, regardless of the location of the Contingencies associated with the Reportable Disturbance within the Reserve Sharing Group, only if:

1. All Reportable Disturbances being considered as contributing to the Reserve Sharing

² Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Group's Reportable Disturbance condition each had an associated call by the group member with the Reportable Disturbance for the activation of Contingency Reserves from one or more other group members, and

2. The Reserve Sharing Group's Reportable Disturbance was either based on Simultaneous Contingencies with a combined magnitude in excess of the most severe single Contingency, or was a subsequent contingency that occurred more than one minute after the start of a Reportable Disturbance but within the Reportable Disturbance Period.

Question 3:

Clarify the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Response 3:

As discussed in the response to Question 1, the exclusion from compliance evaluation does not apply to all Disturbances that exceed the most severe single Contingency.

Measure M1 of BAL-002-0 details the calculation of the percentage recovery for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or Reserve Sharing Group's most severe single contingency loss. In addition to describing the calculation, the measure indicates that there will be a calculation of average percent recovery for Reportable Disturbances during a given quarter and a similar calculation for excludable Disturbances. Since calculation of both metrics is described in Measure M1, the phrase "excluded from compliance evaluation" indicates that the specified disturbances shall not be included in the calculation of "average percent recovery for Reportable Disturbances," but will be included in the "average percent recovery for excludable Disturbances," as specified in Measure M1. As indicated in Section D.1, compliance with the DCS will be measured on a percentage basis using these measures.

While an entity's average percent recovery for Reportable Disturbances may be calculated as 100%, BAL-002-0 Requirement R3 still requires a Balancing Authority or Reserve Sharing Group to "activate sufficient contingency reserves to comply with the DCS." The Compliance Enforcement Authority, when verifying compliance with BAL-002-0, will be taking numerous factors into account, including whether or not the Balancing Authority or Reserve Sharing Group carried at least enough Contingency Reserve to cover the most severe single contingency. However, the determination of whether or not a violation of the standard has occurred rests with the Compliance Enforcement Authority. To the extent explicit limits are desired, they must be clearly specified in the requirements of the standard.



NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Window Open

February 15–26, 2010

Now available at: <https://standards.nerc.net/CurrentBallots.aspx>

Project 2009-19: Interpretation of BAL-002-0 for the Northwest Power Pool Reserve Sharing Group

An initial ballot window for an interpretation of standard BAL-002-0 — Disturbance Control Performance, Requirements R4 and R5, for the Northwest Power Pool Reserve Sharing Group is now open **until 8 p.m. EST on February 26, 2010**.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: <https://standards.nerc.net/CurrentBallots.aspx>

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

The Northwest Power Pool Reserve Sharing Group requested clarification of language related to contingencies excluded from compliance evaluation.

The request and interpretation can be found on the project page:

<http://www.nerc.com/filez/standards/Project2009-19 Interpretation BAL-002-0 NWPP.html>

Standards Development Process

The [Reliability Standards Development Procedure](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.*



NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Ballot Pool and Pre-ballot Window

January 15–February 15, 2010

Now available at: <https://standards.nerc.net/BallotPool.aspx>

Project 2009-19: Interpretation of BAL-002-0 for the Northwest Power Pool Reserve Sharing Group (NWPP RSG)

An interpretation of standard BAL-002-0 — Disturbance Control Performance, Requirements R4 and R5, for the Northwest Power Pool Reserve Sharing Group is posted for a 30-day pre-ballot review. Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. EST on February 15, 2010.**

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2009-19_RFI_NWPPRSG_in@nerc.com.

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

The Northwest Power Pool Reserve Sharing Group requested clarification of language related to contingencies excluded from compliance evaluation.

The request and interpretation can be found on the project page:

http://www.nerc.com/filez/standards/Project2009-19_Interpretation_BAL-002-0_NWPP.html

Standards Development Process

The [Reliability Standards Development Procedure](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.*



NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Results

Now available at: <https://standards.nerc.net/Ballots.aspx>

Project 2009-19: Interpretation of BAL-002-0 for the Northwest Power Pool Reserve Sharing Group (NWPP RSG)

The initial ballot for an interpretation of standard BAL-002-0 — Disturbance Control Performance, Requirements R4 and R5, for the Northwest Power Pool Reserve Sharing Group ended on February 26, 2010.

Ballot Results

Voting statistics are listed below, and the [Ballot Results](#) Web page provides a link to the detailed results:

Quorum: 89.83%
Approval: 48.60%

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps

As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background

The Northwest Power Pool Reserve Sharing Group requested clarification of language related to contingencies excluded from compliance evaluation.

The request and interpretation can be found on the project page:

<http://www.nerc.com/filez/standards/Project2009-19 Interpretation BAL-002-0 NWPP.html>

Standards Development Process

The [Reliability Standards Development Procedure](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

*For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.*

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Newsroom

Site Map

Contact NERC

SEARCH NERC.com

Advanced Search

GO

User Name

Password

Log in

Register

-Ballot Pools

-Current Ballots

-Ballot Results

-Registered Ballot Body

-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG_in
Ballot Period:	2/15/2010 - 2/26/2010
Ballot Type:	Initial
Total # Votes:	212
Total Ballot Pool:	236
Quorum:	89.83 % The Quorum has been reached
Weighted Segment Vote:	48.60 %
Ballot Results:	The standard will proceed to recirculation ballot.

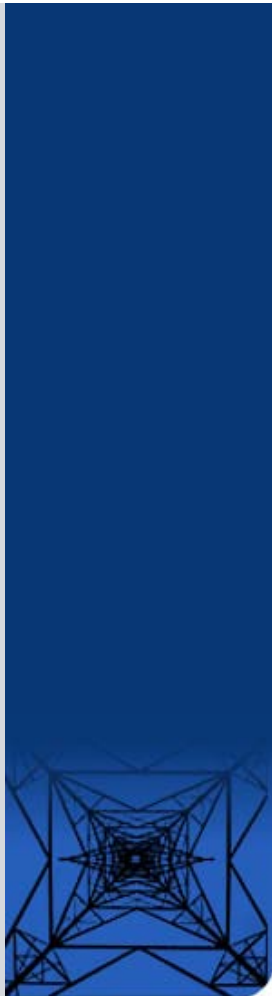
Summary of Ballot Results								
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	61	1	26	0.491	27	0.509	4	4
2 - Segment 2.	12	1	6	0.6	4	0.4	0	2
3 - Segment 3.	54	1	27	0.587	19	0.413	4	4
4 - Segment 4.	15	1	5	0.385	8	0.615	2	0
5 - Segment 5.	43	1	16	0.485	17	0.515	5	5
6 - Segment 6.	33	1	10	0.4	15	0.6	2	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.4	2	0.2	2	0.2	0	2
9 - Segment 9.	4	0.3	1	0.1	2	0.2	1	0
10 - Segment 10.	8	0.6	3	0.3	3	0.3	1	1
Totals	236	7.3	96	3.548	97	3.752	19	24

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Negative	View
1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		

1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils		
1	E.ON U.S. LLC	Larry Monday	Abstain	
1	East Kentucky Power Coop.	George S. Carruba		
1	Empire District Electric Co.	Ralph Frederick Meyer	Negative	View
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	ITC Transmission	Elizabeth Howell	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Long Island Power Authority	Jonathan Appelbaum	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena		
1	New York State Electric & Gas Corp.	Henry G. Masti	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	View
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Negative	
1	PacifiCorp	Mark Sampson	Negative	View
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Negative	View
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sierra Pacific Power Co.	Richard Salgo	Negative	View
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Abstain	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Tampa Electric Co.	Thomas J. Szelistowski	Negative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Negative	View
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Jason L. Murray	Negative	View
2	BC Transmission Corporation	Faramarz Amjadi	Negative	
2	California ISO	Timothy VanBlaricom	Affirmative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool	Charles H Yeung		
3	Alabama Power Company	Bobby Kerley	Affirmative	

3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock		
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Black Hills Power	Andy Butcher	Negative	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L. Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Manitoba Hydro	Greg C Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Muters	Affirmative	
3	PacifiCorp	John Apperson	Negative	View
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Negative	View
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill	Negative	View
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Negative	View
3	Seattle City Light	Dana Wheelock	Negative	View
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada		
3	Tampa Electric Co.	Ronald L Donahey	Negative	View
3	Turlock Irrigation District	Casey Hashimoto	Negative	
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Negative	View
4	Northern California Power Agency	Fred E. Young	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Negative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	View
4	Seattle City Light	Hao Li	Negative	View

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer		
5	Avista Corp.	Edward F. Groce	Negative	View
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	Chelan County Public Utility District #1	John Yale	Negative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	Consolidated Edison Co. of New York	Edwin E Thompson	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Negative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	JEA	Donald Gilbert	Affirmative	View
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Northern States Power Co.	Liam Noailles	Negative	View
5	Orlando Utilities Commission	Richard Kinan		
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Portland General Electric Co.	Gary L Tingley	Negative	
5	PPL Generation LLC	Mark A. Heimbach	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	RRI Energy	Thomas J. Bradish	Negative	View
5	Sacramento Municipal Utility District	Bethany Wright	Negative	View
5	Salt River Project	Glen Reeves	Negative	View
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South California Edison Company	Ahmad Sanati		
5	South Carolina Electric & Gas Co.	Richard Jones	Abstain	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Black Hills Corp	Tyson Taylor	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Chris Lyons	Negative	
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Kansas City Power & Light Co.	Thomas Saitta	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Louisville Gas and Electric Co.	Daryn Barker	Abstain	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Gregory D Maxfield	Negative	View
6	Portland General Electric Co.	John Jamieson	Negative	
6	PP&L, Inc.	Thomas Hyzinski	Negative	View



6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson		
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	View
6	RRI Energy	Trent Carlson		
6	Salt River Project	Mike Hummel	Negative	View
6	Santee Cooper	Suzanne Ritter	Negative	View
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Co.	Marcus V Lotto		
6	SunGard Data Systems	Christopher K Heisler		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8	Edward C Stein	Edward C Stein		
8	James A Maenner	James A Maenner	Negative	View
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Roger C Zaklukiewicz	Roger C Zaklukiewicz	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Negative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	Oregon Public Utility Commission	Jerome Murray	Negative	View
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Negative	View
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Negative	View
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacque Smith	Abstain	
10	SERC Reliability Corporation	Carter B Edge		
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

[Legal and Privacy](#) : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

 [Account Log-In/Register](#)

Copyright © 2009 by the North American Electric Reliability Corporation. : All rights reserved.
A New Jersey Nonprofit Corporation

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard	
Date submitted:	September 2, 2009
Date accepted:	September 2, 2009
Contact information for person requesting the interpretation:	
Name:	Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization:	Northwest Power Pool Reserve Sharing Group
Telephone:	503-445-1074
E-mail:	jerry.rust@nwpp.org
Identify the standard that needs clarification:	
Standard Number (include version number):	BAL-002-0
Standard Title:	Disturbance Control Performance
Identify specifically what requirement needs clarification:	
<u>Requirement Number and Text of Requirement:</u>	
B. Requirements	
* * *	
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	
R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value. R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.	
* * *	
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. * * * Compliance may be demonstrated by either	

of the following two methods:

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

D. Compliance

1.4 Additional Compliance Information

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Clarification needed:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

- (1) although a Disturbance¹ that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
- (2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve

¹ Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

- (3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for “enough Contingency Reserve to cover the most severe single Contingency”) meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute “Reportable Disturbances.” See Section 1.4 of Part D of BAL-002-0 (where the “Additional Compliance Information” includes a definition of “Reportable Disturbance”).

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (see, e.g., Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that “An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.”)

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Response:

The Balancing Authority Controls Standard Drafting Team was originally assigned to provide

3353 Peachtree Road NE
Atlanta, GA 30326
www.nerc.com

a response to the interpretation request. The original interpretation failed to achieve a two-thirds approval from the industry. NERC appointed a new IDT to develop this interpretation. On July 24, 2012, the team provided the following response to the questions raised:

Question 1: Although a Disturbance² that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?

Response: The IDT agrees that the Disturbance would be excluded from compliance. The BAL-002 **Additional Compliance Information section** clearly states:

Simultaneous Contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

For clarity the IDT would like to explain the Team's basis concerning some of the terminology used.

Most Severe Single Contingency (MSSC) – this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction. Although Requirement R3.1 mandates an annual "review" that does not mean an annual value. Note that Requirement R3.1 determines a "prospective" MSSC. MSSC is a variable that the BA knows and operates to in real time. The largest operating generator is known and monitored by a BA. The largest known common mode failure is predefined for the BA; the largest single firm transaction is approved by the BA. Thus the BA knows its MSSC which can vary from hour to hour and minute to minute.

To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC).

An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition.

BAL-002 has two categories (1) Compliance and reporting (for Reportable Disturbances that must comply with the disturbance recovery criteria within the Disturbance Recovery Period) and (2) Reporting only (for specified disturbances and system conditions) events that are excluded from meeting Requirement R4.

² Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

The **Compliance and reporting category** is designed to be used to accumulate all DCS events that are subject to compliance to BAL-002 Requirement R4 (i.e. recover ACE within 15 minutes). These include all single assets as well as all pre-defined common mode failures. The standard originally created R_i (the average percent recovery for a Reportable Disturbance) as a measure of the quarterly compliance for Reportable Disturbances. Where all events greater than 80% were mandatory to report and those less than 80% were permitted to be reported (thus encouraging reporting smaller events).

The **Reporting only category** is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC.

The **Performance Standard Reference document** initially included with the DCS standard does states "Where RSGs exist, the Regional Reliability Council is to decide either to report on a BA basis or an RSG basis. If an RSG has dynamic membership then... required ...to report on a BA basis.

Question 2: With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?

Response: Requirement R5 is directed to RSGs, where RSG is defined in the NERC Glossary as:

A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

The standard provides flexibility to BAs regarding the use or non-use of RSGs (Requirement R1.1). Requirement R2 affords the members flexibility in how they organize themselves.

Requirement R1.1 allows, at the option of a BA, or RSG to take on all or part of the

responsibilities that BAL-002 places on a BA. However, Requirement R5 allows a BA to “call for activation” of reserves [aka dynamic allocation of membership] moreover, there is no ad hoc recognition of such an RSG’s multiple contingencies since a contingency in one BA may or not be referred to the RSG, and the simultaneous contingency in another BA is unknown.

The Technical Document does allow for a pre-acknowledged RSG to report on a composite basis. It can be interpreted that such a pre-acknowledged RSG entity assumes all of the obligations and rights afforded to a single BA and in that case such an RSG would be afforded the same Exclusions as the Exclusions afforded a BA.

In summary, the interpretation is as follows:

- The Standard was written to provide pre-acknowledged RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a pre-acknowledged RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period.

The standard, while recognizing dynamically allocated RSGs, does NOT provide the members of dynamically allocated RSGs exclusions from DCS compliance evaluation on an RSG basis. For members of dynamically allocated RSGs, the exclusions are provided only on a member BA by member BA basis.

Question 3: Clarify the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Response: The **Additional Compliance Information** section clearly states:

Simultaneous contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the Most Severe Single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Although Requirement R3 does mandate that a BA or RSG activate sufficient Contingency Reserves to comply with DCS for every Reportable Disturbance, there is no requirement to comply with or even report disturbances that are below the Reportable Disturbance level. The averaging obligation does incent calculation and reporting of such lesser events.

If a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance,

but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency. Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g., Performance Standards Document, Version 3* (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that “An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.”)

Unofficial Comment Form

Project 2009-19 – Interpretation of BAL-002-0 for NWPP

Please **DO NOT** use this form to submit comments. Please use the [electronic form](#) located at the link below to submit comments on the Interpretation of BAL-002-0 (R4, R5, and Section D 1.4) for the Northwest Power Pool Reserve Sharing Group. The electronic comment form must be completed by 8 p.m. ET **September 4, 2012**.

http://www.nerc.com/filez/standards/Project2009-19_Interpretation_BAL-002-0_NWPP.html

If you have questions please contact Darrel Richardson at darrel.richardson@nerc.net or by telephone at (609) 613-1848.

Background Information

This posting is soliciting formal comment.

This Request for Interpretation (RFI) was submitted by the Northwest Power Pool Reserve Sharing Group (NWPP) to provide clarity in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are; 1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; 2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and 3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

NWPP notes that without further clarity this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic

operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

The original interpretation failed to achieve a two-thirds approval from the industry. The original Interpretation Drafting Team (IDT) did not believe that an interpretation could be developed that would provide sufficient clarity on the requestors points of interest without the using the “Additional Compliance Information” elements within the standard. Initially, the IDT believed that the “Additional Compliance Information” section could not be used to interpret the requirements of a standard. The Standards Committee (SC) agreed and the interpretation was tabled. The NERC BOT later ruled that the “Additional Compliance Information” elements should be recognized as part of the standard and that they could be utilized to provide guidance on the meaning of the requirements. The SC re-activated the project in May 2012. The IDT has reviewed the NWPP request and developed this interpretation pursuant to the NERC Guidelines for Interpretation Drafting Teams, which is available at:

[http://www.nerc.com/files/Guidelines for Interpretation Drafting Teams Approved April 2011.pdf](http://www.nerc.com/files/Guidelines%20for%20Interpretation%20Drafting%20Teams%20Approved%20April%202011.pdf))

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Please review the request for an interpretation, the associated standard, and the draft interpretation and then answer the following questions.

1. Do you agree with **Response 1** of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

☐ Yes
☐ No

Comments:

2. Do you agree with **Response 2** of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

☐ Yes
☐ No

Comments:

3. Do you agree with **Response 3** of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

☐ Yes
☐ No

Comments:

Standards Announcement

Project 2009-19

Interpretation of BAL-002-0 - NWPP Reserve Sharing Group

Successive Ballot Window Open through 8 p.m. Tuesday, September 4, 2012

[Now Available](#)

A successive ballot for the Interpretation of BAL-002-0 - Disturbance Control Performance Requirements R4 and R5 for NWPP Reserve Sharing Group is open through **8 p.m. Eastern on Tuesday, September 4, 2012.**

Instructions

Members of the ballot pool associated with this project may log in and submit their vote for the interpretation by clicking [here](#).

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the [electronic comment form](#). During the ballot window, balloters who wish to submit comments with their ballot may no longer enter comments on the balloting screen, but may still enter the comments through the electronic comment form. **Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information and are not required to answer any other questions.**

Next Steps

The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the interpretation. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background

Northwest Power Pool Reserve Sharing Group (NWPP) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are; 1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; 2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all

Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and 3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Additional information is available on the [project page](#).

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Interpretation of BAL-002-0 for NWPP Reserve Sharing Group Project 2009-19

Ballot Pool Forming:	July 25, 2012 – August 23, 2012
Formal Comment Period Open:	July 25, 2012 – September 4, 2012
Upcoming: Successive Ballot	August 23, 2012 – September 4, 2012

[Now Available](#)

A formal comment period for the Interpretation of BAL-002-0 - Disturbance Control Performance Requirements R4 and R5 by NWPP Reserve Sharing Group is open through **8 p.m. Eastern on Tuesday, September 4, 2012** and a ballot pool is forming through **8 a.m. Eastern Thursday, August 23, 2012**.

Instructions for Joining Ballot Pool

Registered Ballot Body members must join the ballot pool to be eligible to vote in balloting of the Interpretation of BAL-002-0 Requirements R4 and R5 at [Join Ballot Pool](#).

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list servers.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list server for this ballot pool is:

Successive ballot: bp-2009-19_BAL-002_SB_in@nerc.com

The ballot pool is open **through 8 a.m. Eastern on Thursday, August 23, 2012**.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Tuesday, September 4, 2012**. Please use this [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the [project page](#).

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the [electronic comment form](#). During the ballot window, balloters who wish to submit comments with their ballot may no longer enter comments on the balloting screen, but may

still enter the comments through the electronic comment form. **Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information on the electronic survey and are not required to answer any other questions.**

Next Steps

A Successive ballot of the interpretation will be conducted beginning Thursday, August 23, 2012 through 8 p.m. Eastern on Tuesday, September 4, 2012.

Background

Northwest Power Pool Reserve Sharing Group (NWPP) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are; 1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; 2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and 3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Additional information is available on the [project page](#).

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2009-19 – Interpretation of BAL-002-0 - NWPP Reserve Sharing Group

Successive Ballot Results

[Now Available](#)

A successive ballot for the Interpretation of BAL-002-0 - Disturbance Control Performance Requirements R4 and R5 for NWPP Reserve Sharing Group concluded on Tuesday, September 4, 2012.

Voting statistics are listed below, and the [Ballot Results](#) page provides a link to the detailed results.

Ballot Results
Quorum: 79.21%
Approval: 87.78%

Next Steps

The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the interpretation. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background

Northwest Power Pool Reserve Sharing Group (NWPP) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are; 1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; 2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and 3) the meaning of the phrase “excluded

from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Additional information is available on the [project page](#).

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Newsroom

Site Map

Contact NERC

SEARCH NERC.com

Advanced Search

GO

User Name

Password

Log in

Register

-Ballot Pools

-Current Ballots

-Ballot Results

-Registered Ballot Body

-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2009-19 Successive Ballot BAL-002 July 2012_in
Ballot Period:	8/23/2012 - 9/4/2012
Ballot Type:	Initial
Total # Votes:	282
Total Ballot Pool:	356
Quorum:	79.21 % The Quorum has been reached
Weighted Segment Vote:	87.78 %
Ballot Results:	The drafting team will review comments received.

Summary of Ballot Results								
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	94	1	54	0.794	14	0.206	8	18
2 - Segment 2.	10	0.9	8	0.8	1	0.1	0	1
3 - Segment 3.	81	1	48	0.857	8	0.143	6	19
4 - Segment 4.	25	1	14	0.933	1	0.067	4	6
5 - Segment 5.	75	1	45	0.938	3	0.063	8	19
6 - Segment 6.	52	1	31	0.886	4	0.114	9	8
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	10	0.6	6	0.6	0	0	1	3
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.6	4	0.4	2	0.2	1	0
Totals	356	7.3	212	6.408	33	0.893	37	74

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	El Paso Electric Company	Dennis Malone	Affirmative	
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil		
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Matthey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Brett A. Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	

1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative
1	Salt River Project	Robert Kondziolka	Affirmative
1	Santee Cooper	Terry L Blackwell	Abstain
1	Seattle City Light	Pawel Krupa	Affirmative
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative
1	Snohomish County PUD No. 1	Long T Duong	Abstain
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative
1	Southern California Edison Company	Steven Mavis	Affirmative
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative
1	Southern Illinois Power Coop.	William Hutchison	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative
1	Sunflower Electric Power Corporation	Noman Lee Williams	
1	Tennessee Valley Authority	Howell D Scott	Negative
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative
1	Tucson Electric Power Co.	John Tolo	Affirmative
1	Turlock Irrigation District	Esteban Martinez	Affirmative
1	United Illuminating Co.	Jonathan Appelbaum	Negative
1	Westar Energy	Allen Klassen	Affirmative
1	Western Area Power Administration	Brandy A Dunn	Affirmative
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative
2	Alberta Electric System Operator	Ken A Gardner	Affirmative
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative
2	ISO New England, Inc.	Kathleen Goodman	
2	Midwest ISO, Inc.	Marie Knox	Affirmative
2	New Brunswick System Operator	Alden Briggs	Affirmative
2	New York Independent System Operator	Gregory Campoli	Affirmative
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative
3	AEP	Michael E Deloach	
3	Alabama Power Company	Robert S Moore	Affirmative
3	Ameren Services	Mark Peters	Affirmative
3	APS	Steven Norris	Affirmative
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative
3	Central Electric Power Cooperative	Adam M Weber	Negative
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative
3	City of Clewiston	Lynne Mila	
3	City of Green Cove Springs	Gregg R Griffin	Abstain
3	City of Redding	Bill Hughes	Affirmative
3	City of Tallahassee	Bill R Fowler	Affirmative
3	Colorado Springs Utilities	Charles Morgan	Affirmative
3	ComEd	Bruce Krawczyk	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative
3	Consumers Energy	Richard Blumenstock	Affirmative
3	CPS Energy	Jose Escamilla	Abstain
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain
3	El Paso Electric Company	Tracy Van Slyke	Affirmative
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative
3	Florida Municipal Power Agency	Joe McKinney	
3	Florida Power Corporation	Lee Schuster	
3	Georgia Power Company	Danny Lindsey	Affirmative
3	Grays Harbor PUD	Wesley W Gray	Affirmative
3	Great River Energy	Brian Glover	Affirmative
3	Gulf Power Company	Paul C Caldwell	Affirmative
3	Hydro One Networks, Inc.	David Kiguel	Affirmative
3	Imperial Irrigation District	Jesus S. Alcaraz	
3	JEA	Garry Baker	
3	KAMO Electric Cooperative	Theodore J Hilmes	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative

3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Pepco Holdings, Inc.	Mark R Jones		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Steve Wickel	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Turlock Irrigation District	James Ramos	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney		
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	

4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative
4	Seattle City Light	Hao Li	Affirmative
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative
4	Tacoma Public Utilities	Keith Morissette	Affirmative
4	Turlock Irrigation District	Steven C Hill	Affirmative
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative
5	AEP Service Corp.	Brock Ondayko	Negative
5	Amerenue	Sam Dwyer	Affirmative
5	Arizona Public Service Co.	Edward Cambridge	Affirmative
5	Avista Corp.	Edward F. Groce	Affirmative
5	BC Hydro and Power Authority	Clement Ma	Affirmative
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	
5	Calpine Corporation	Phillip Porter	
5	City and County of San Francisco	Daniel Mason	Abstain
5	City of Austin dba Austin Energy	Jeanie Doty	
5	City of Redding	Paul A. Cummings	Affirmative
5	City of Tallahassee	Karen Webb	Affirmative
5	Cleco Power	Stephanie Huffman	Affirmative
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative
5	Consumers Energy Company	David C Greyerbiehl	Affirmative
5	Dairyland Power Coop.	Tommy Drea	
5	Deseret Power	Philip B Tice Jr	Affirmative
5	Detroit Edison Company	Christy Wicke	Affirmative
5	Detroit Renewable Power	Marcus Ellis	
5	Duke Energy	Dale Q Goodwine	Negative
5	El Paso Electric Company	David Hawkins	Affirmative
5	Essential Power, LLC	Patrick Brown	Affirmative
5	Exelon Nuclear	Michael Korchynsky	Affirmative
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative
5	Florida Municipal Power Agency	David Schumann	
5	Great River Energy	Preston L Walsh	
5	Hydro-Québec Production	Roger Dufresne	
5	Imperial Irrigation District	Marcela Y Caballero	Abstain
5	JEA	John J Babik	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative
5	Kissimmee Utility Authority	Mike Blough	
5	Lakeland Electric	James M Howard	
5	Lincoln Electric System	Dennis Florom	Affirmative
5	Los Angeles Department of Water & Power	Kenneth Silver	
5	Manitoba Hydro	S N Fernando	Affirmative
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain
5	MEAG Power	Steven Grego	
5	Muscatine Power & Water	Mike Avesing	Affirmative
5	Nebraska Public Power District	Don Schmit	Affirmative
5	New York Power Authority	Wayne Sipperly	Affirmative
5	NextEra Energy	Allen D Schriver	Affirmative
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative
5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative
5	PacifiCorp	Sandra L. Shaffer	Affirmative
5	Platte River Power Authority	Roland Thiel	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative
5	PPL Generation LLC	Annette M Bannon	Abstain
5	Proven Compliance Solutions	Mitchell E Needham	Abstain
5	Public Utility District No. 1 of Chelan County	John Yale	Affirmative
5	Public Utility District No. 1 of Lewis County	Steven Grega	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative
5	Salt River Project	William Alkema	Affirmative
5	Santee Cooper	Lewis P Pierce	Abstain
5	Seattle City Light	Michael J. Haynes	Affirmative

5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	Turlock Irrigation District	Marty Rojas	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	El Paso Electric Company	Tony Soto	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipp		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	Progress Energy	John T Sturgeon	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen		
6	Southern California Edison Company	Lujuanna Medina	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Turlock Irrigation District	Amy Petersen	Affirmative	
6	Westar Energy	Grant L Wilkerson		



6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Edward C Stein	Affirmative	
8	Ascendant Energy Services, LLC	Raymond Tran	Affirmative	
8	Energy Mark, Inc.	Howard F. Illian	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Abstain	
8	Volkman Consulting, Inc.	Terry Volkman		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	
10	Southwest Power Pool RE	Emily Pennel	Abstain	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

[Legal and Privacy](#)

404.446.2560 voice : 404.446.2595 fax

Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326

Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

 [Account Log-In/Register](#)

Copyright © 2012 by the North American Electric Reliability Corporation. : All rights reserved.
A New Jersey Nonprofit Corporation

Name (17 Responses)
Organization (17 Responses)
Group Name (10 Responses)
Lead Contact (10 Responses)

Contact Organization (10 Responses)

IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. Please be sure to click on 'finish' to complete the submittal process. (0 Responses)

Comments (27 Responses)
Question 1 (23 Responses)
Question 1 Comments (23 Responses)
Question 2 (23 Responses)
Question 2 Comments (23 Responses)
Question 3 (22 Responses)
Question 3 Comments (23 Responses)

Individual
B
N
Company XYZ
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below: "Most Severe Single Contingency (MSSC) – this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction." We do not agree the term "firm transaction". The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA's resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction. Further, the term "firm transaction" is subject to debate as to whether the firmness is in the energy component or in the transmission service component. If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word "firm" from the clarification section.
Yes
Yes
(1) We generally agree with the proposed interpretation. However, we are not sure if this request fits well into NERC's criteria for acceptance as a valid request since it appears that the requester asks specifically on the compliance implications and compliance elements. We suggest the interpretation drafting team (IDT) to evaluate whether or not the request is a valid one that seeks clarity on the requirements, rather than on the compliance aspects of the standard/requirements. If the IDT does assess that the questions are addressing a compliance issue, then we suggest the IDT to bring this to the attention of the Standards Committee for a determination of the appropriate means to address the questions. (2) The IESO agrees with NERC's interpretation of BAL-002. However, we believe additional discussion and thought need to be applied to other Standards to ensure that no gaps or overlaps exist in both task execution and Standard application. Different Standards obligate Reliability Entities to fulfill certain tasks as it pertains to balancing conditions. This includes: • BAL- 002 outlines

obligations to balance following Reportable Disturbances; • EOP-002 outlines obligations to balance during Capacity and Energy Emergencies; and • TOP-001 outlines obligations to balance during System Emergencies. All of these Standards have similarities but need interpretation to ensure consistent application. These interpretations are based on an understanding of the NERC Functional Model and upon clear statements in the purpose and requirement sections in the Standards. We believe that the objective of each of the Standards list above must be clarified to reduce confusion and support consistent application.
Individual
Nazra Gladu
Manitoba Hydro
Yes
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes
Yes
Yes
Individual
Thad Ness
American Electric Power
No
We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.
No
We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided. For example, it is not clear to us exactly what “pre-acknowledged” or “dynamic” means in regards to Reserve Sharing Groups. These terms are not found anywhere within the standard itself, nor are they commonly used to describe or qualify Reserve Sharing Groups.
No
We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.
Individual
Oliver Burke
Entergy Services, Inc.
Yes

Yes
Yes
Individual
John Appel
Public Utility District #1 of Chelan County
Chelan PUD supports the interpretation of BAL-002-0 on behalf of the NWPP.
Individual
Don Schmit
Nebraska Public Power District
Yes
The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Yes
The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Yes
The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Arizona Public Service Company
Yes
Yes
Yes
Individual
Carter Edge
SERC
No
The interpretations process is not an appropriate mechanism to address a compliance monitoring and enforcement issue. Further, the words in the requirements do not support the interpretation, no matter how much the interpretation reflects how the industry and ERO have historically approached the Disturbance Control Standard. The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Specifically, Requirement 1 requires each Balancing Authority to have access to and/or operate Contingency Reserve to respond to Disturbances. Prior to penalties and sanctions under Section 215, the consequence of failing DCS was to require an increase in contingency reserves. This is the "compliance evaluation" referred to under Section D. The expectation is that Balancing Areas respond to the loss of resources regardless of magnitude to restore ACE and minimize the risk to reliable operation of being "out of balance". There was recognition, however, that interconnected operations increased the reliability of the grid by reducing the consequences of a single area being out of balance at any given time and thus allowed the collective greater utilization of installed capacity to

serve load rather than retain it as contingency reserves. Thus, the concept of “most severe single contingency” (MSSC) as a criterion against which to require additional contingency reserve was employed and for large contingencies may require more time to respond. Fifteen minutes is a “benchmark” time-frame that is reasonable to expect a Balancing Area to recover from a credible contingency. There is nothing magical about that time (it used to be 10 minutes), but the BA should not “lean” on the system longer than is necessary regardless of the magnitude. Performance outside this benchmark can only be determined by an inspection of the facts and circumstances of each instance. All Balancing Authorities and Reserve Sharing Groups are required to review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies. The NERC glossary defines Contingency as the “unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element”. Thus, the compliance action or inaction (“decline to pursue”) with respect to the performance of an entity against the stated requirements in the standard is a matter of the CMEP and should not be addressed through the standards interpretations process. Compliance activity should be based on the facts and circumstances of each case measured against the performance requirements of the standard. Standards (including interpretations) are for describing the behaviors and actions of registered entities necessary for the reliable planning and operation of the bulk power system not the Compliance Enforcement Authority. Informed and expert discretion rather than this interpretation (which requires inaction) is a better answer for the Reliability Assurer. Further, ALR 2-5 has a stated purpose as a measure of how much risk a system is exposed to for extreme or unusual contingencies (Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation). The results of ALR 2-5 are expected to help validate current contingency reserve requirements and document how often these “extreme or unusual” contingencies occur. These activities should continue.

No

See answer to question #1.

No

See Response to question #1.

Group

ISO-RTO Standards Review Committee

Terry Bilke

MISO

Yes

We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below: “Most Severe Single Contingency (MSSC) – this can be the loss of the BA’s or RSG’s single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction.” We do not agree the term “firm transaction”. The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA’s resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction. Further, the term “firm transaction” is subject to debate as to whether the firmness is in the energy component or in the transmission service component. If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word “firm” from the clarification section.

Yes

Yes

It might be clearer if the reponse added the phrase [of the Disturbance Control Standard] after “loss

shall be reported, but excluded from compliance evaluation". Following a large event, the BA would still be accountable for other standards (e.g. IRO standards)
Group
ACES Power Marketing Standards Collaborators
Ben Engelby
ACES Power Marketing
Yes
We conceptually agree with the position of the interpretation. However, we believe that the current response expands issues that were not raised in the original question. One example is that the "MSSC value at any given time may be more or less than the annually identified prospective MSSC" is contradictory to the interpretation. How could the MSSC value could ever be higher than the list of candidate MSSCs identified in the annual review. Also, in the "reporting only" category in response 1, the IDT incorrectly characterizes that the ERO would have authority or the information to alert the BA that two (or more) contingencies must be considered as a single event and thus considered as the MSSC. The ERO does not determine the MSSC, the BA or RSG makes that determination. For simplicity and clarity, we recommend that the interpretation state: Disturbances greater than MSSC are excluded from the compliance calculation, based on the additional compliance information section of BAL-002-0. The IDT could strike everything following this statement from the interpretation and would convey the same message in a more clear and concise manner.
Yes
We largely agree with the interpretation. However, we want to point out that the concept of pre-acknowledged RSGs have disincentivized Adjacent Balancing Authorities (not in a pre-acknowledged RSG) to provide reserves in less than 10 minutes even if they are capable. If an Adjacent Balancing Authority provides emergency energy in an amount that exceeds its own MSSC with a ramp less than 10 minutes and fails to recover its ACE from within 15 minute of the initial disturbance, the Adjacent BA may be found non-compliant despite the fact the it provided the appropriate reliability assistance. Compliance should not disincentivize actions that ensure reliability.
Yes
We agree for the most part with this interpretation. However, we do have a few points we would like to address. We recommend striking the entire second paragraph because it is irrelevant. The standard does not say comply with DCS "for every reportable disturbance." The key is whether a BA is required to recover ACE within 15 minutes for contingencies greater than MSSC, and that answer is no. The IDT should keep the interpretation simple. A recommendation for wording the interpretation: A BA is not required to recover ACE within 15 minutes for contingencies greater than MSSC, as stated in section 1.4 ("Additional Compliance Information"). We recommend that the IDT reduce the amount detail in the rationale and focus on the three questions in the request. The current draft of the interpretation is wordy, confusing and provides excessive details instead of answering the questions that were asked. Also, the IDT did not state that this interpretation would apply to BAL-002-1, which has been enforceable since 4/1/2012. If NERC is going to continue with the interpretation process for BAL-002, the interpretation should apply to both versions of the standard. Finally, we encourage NERC to consolidate standard projects. There are currently 10 standard projects under development for BAL standards. NERC should consider either a consolidation to a reduced amount of BAL projects or even a single project to cover all BAL issues in order to avoid duplication, overlap, inefficient use of resources and confusion.
Group
El Paso Electric
Pablo Oñate
El Paso Electric
Yes
El Paso Electric (EPE) generally supports the first interpretation proposed by the IDT but is concerned with the language immediately following "To be clear..." because it does not acknowledge the fact that many BAs have placed responsibility in the hands of a RSG. The interpretation states that "...a BA is

responsible for the MSSC at all times...". EPE believes that this responsibility should be shared with a RSG, where appropriate. EPE would be more comfortable with an interpretation that read "To be clear a BA or RSG, as applicable, is responsible for the MSSC at all times..."
Yes
EPE generally supports the second interpretation by the IDT but requests that IDT clarify the scope of compliance evaluations for BAs who are part of a RSG and experienced a reportable event, without regard to whether any individual BA member of the RSG requested assistance. If a RSG determines that the group as a whole complied with CPS then there should be no need for any individual BA review or reporting under R5, without regard to whether the BA called for reserve activation from other RSG members, or not. The interpretation should include this clarification.
Yes
No Comment.
Individual
x
x
Individual
linda Horn
Wisconsin Electric Power Company
We are supporting the comments of MISO.
Group
Duke Energy
Greg Rowland
Duke Energy
Yes
We suggest that there should be a SAR to define the terms MSSC and "excludable disturbance" add them to the NERC Glossary.
No
It's not clear what the drafting team is saying, particularly the reference to "dynamic allocation of membership". What's the difference between pre-acknowledged RSGs and dynamically allocated RSGs, and why are the exclusion rules different?
No
It's not clear what the drafting team is saying. Does "excluded from compliance evaluation" mean that R4 does not apply to Disturbances that exceed the MSSC for a BA or RSG? Does it matter if the RSG is pre-acknowledged or dynamically allocated? The drafting team's response to Question 2 seems to indicate that it does matter. We agree that DCS is not applicable for losses greater than the MSSC, and also that DCS compliance is not required for losses less than 80% of the MSSC (or lower if a lower threshold is adopted for DCS reporting). This interpretation is performed on BAL-002-0, but the current effective standard is BAL-002-1 as of 4-1-2012. If the interpretation is approved, what is its applicability to BAL-002-1? Under BAL-002-0 the default Disturbance Recovery Period could be adjusted to better suit the needs of an Interconnection (R4.2) and the default Contingency Reserve Restoration Period could be adjusted to better suit the reliability targets of the Interconnection (R6.2), both based on analysis approved by the NERC Operating Committee. This has been deleted from both requirements in BAL-002-1.
Group
Associated Electric Cooperative Inc - JRO00088
David Dockery
Associated Electric Cooperative Inc
No
Remove: The final paragraph beginning with "The Performance Standard Reference document initially

included..." Rationale: A text-search of BAL-002-0, downloaded from the NERC website, fails to yield any instances of the word "dynamic", meaning that it appears nowhere within the four-corners of the BAL-002-0 Standard. Responsible Entities are subject only to the Standard's requirements as written and within its Effective Dates 4/1/2005 to 8/5/2010, when BAL-002-1 effectively replaced it. NERC's BOT Approved August 2, 2006 filing with The Commission appears to contain the oldest copy of FERC approved NERC Glossary of Terms Used in Reliability Standards. It contains no instances of the word "dynamic" that correspond in any way to Reserve Sharing Group membership, although "Reserve Sharing Group" and "Reportable Disturbance" are defined within that document. Although the SDT asserts the augmented concept of RSG dynamic membership, those references within this interpretation should be stricken because the "dynamic membership" concept clearly does not exist within the "four-corners of the Standard" which was balloted and approved by industry stakeholders. Instead BAL-002-0 wording indicates that each RSG can establish its own guidance, necessary to comply with the Requirements. Requirement R2 provides each Reserve Sharing Group the flexibility concerning its policies governing how it collectively fulfills its responsibility to meet Requirements R3, R4, R5 and R6. However Requirement R5's parenthetical does appear to provide some governance concerning a BA's reporting within a Reserve Sharing Group when they do not call for reserve activation from its other members, that they are subject to individually reporting their performance in responding to that event. (In either case of reporting per R5 parenthetical, the RSG's collectively-committed units' spinning-mass and short-term governor response would have fulfilled the reliability objective of this Standard, unless the Reportable Disturbance's magnitude was much greater than anticipated by the RSG in its entirety.)

No

Replace: The entire answer. With: "Yes." Rationale: In our opinion, the IDT failed to answer Question #2, which could have been answered with a simple "Yes". Instead, they appear to attempt legislating upon particulars of how all RSGs should structure portions of their policies under R2, by again referring to the concept of "dynamic membership". Our understanding is that such expansion of Standard governance can only be done under SDT effort and subsequent industry approval through the ballot process. (See AECI's earlier response to Question 1 above.)

Yes

We agree with this summary determination. In addition, the August 2, 2006 NERC BOT approved, and subsequently FERC accepted Glossary definition for Reportable Disturbance clearly specified that the definition "not be retroactively adjusted in response to observed performance", adding weight to this drafting-team's response to Question 3. (FERC_Filing_Proposed_Reliability_Standards_Docket_RM06-16-000.pdf)

Individual

Greg Travis

Idaho Power Co.

Yes

Yes

Yes

Group

Bonneville Power Administration

Chris Higgins

Transmission Reliability Program

Yes

Yes

Yes
BPA is in support of BAL-002-0 Interpretation and has no comments or concerns at this time.
Group
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
Yes
This interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Yes
Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Yes
Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Yes
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst votes in the Negative for the Interpretation of BAL-002 since ReliabilityFirst believes the drafted interpretation to Question 1 incorrectly expands on the language in Requirement R4 and incorrectly attempts to explain how to comply with the Requirement. If a reportable disturbance occurs (i.e. contingencies that are greater than or equal to 80% of the most severe single Contingency) and is greater than the most severe single Contingency, ReliabilityFirst questions why an entity would not be required to meet the Disturbance Recovery Criterion. Nowhere within the requirements are there exceptions for Reportable Disturbance greater than the most severe single Contingency. Based on R4, the applicable entity "...shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances". For example, if an entity failed to meet the meet the Disturbance Recovery Criterion for a disturbance equaling 110% of their most severe single Contingency, they would potentially be found non-compliant. In addition, ReliabilityFirst does not believe the quasi definition of "Simultaneous Contingencies" within the "Additional Compliance Information" is not enforceable since it is not a Reliability Requirement, and is not even a NERC Defined term.
Yes
ReliabilityFirst disagrees with the drafted interpretation. Regardless of the references to outside sources (the reserve requirement specified in R3.1 of BAL-002-0, the text of Section 1.4 of Part D of BAL-002-0, and the documented history of the development of BAL-002-0), compliance is to be assessed on a requirement by requirement basis. Requirement R4 requires that an applicable entity "...shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of

Reportable Disturbances". Clearly, there is no exception listed within the requirements for Reportable Disturbances greater than the most severe single Contingency.
Individual
Maggy Powell
Exelon Corporation
Yes
Yes
No
Response 3 of the interpretation that requests clarification on the phrase "excluded from compliance evaluation" could be clearer. The first portion of the response gives the impression that the IDT is of the opinion that the obligation to comply with the DCS extends to events larger in magnitude than the MSSC. The paragraphs that follow go on to clarify that an event greater than the MSSC would not be required to recover ACE within 15 minutes, making compliance with the DCS not mandated in these instances. The latter (disturbances exceeding the MSSC being excluded from DCS compliance and 15 minute recovery) is consistent with practice and in line with the interpretation indicated by the NWPP. In order to more fully clarify the interpretation, the IDT should make clear that compliance with the DCS is not mandated for disturbances exceeding the MSSC.
Group
SERC Operating Committee Standards Review Team
Gerald Beckerle
Ameren
Yes
The SERC OC Standards Review Group gladly presents the following comments. The SERC OC Standards Review Group agrees only with the interpretation portion of the response. The Group strongly disagrees there is a need for the additional explanation of the interpretation. The explanation presents more confusion and questions around the Standard. The simple interpretation is very clear and concise.
No
The SERC OC Standards Review Group feels the interpretation and clarification are both very confusing, thus raising numerous other questions. The use of the words "pre-acknowledged RSGS" and "dynamic allocated RSGS" appear to be new terms introduced in the response. Also, a reference to a Technical Document is made in the response. The Group is unsure of what Technical Document the IDT is referring. Nor does the Group understand if such reference to the Technical Document is an agreement with such document by the IDT or if the Technical Document is referenced as to be included in the response and subject to being opened and the processes and procedures of such document being made part of a compliance audit.
Yes
NONE
Individual
Brent Ingebrigtsen
LG&E and KU Services Company
No
The IDT's explanation of MSSC may be unnecessary and confusing, especially statements such as: "MSSC is a variable that the BA knows and operates to in real time." "Thus the BA knows its MSSC which can vary from hour to hour and minute to minute." "To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC)." In the absence of an identifiable/specific reason, which is recognized by the BA

in advance, the real-time MSSC should not exceed the prospective MSSC. Unless such an abnormal situation exists, all evaluations of DCS compliance must be based on the prospective MSSC value. The IDT needs to be very clear with any language suggesting that the real-time MSSC can exceed the planned/recognized/"prospective" MSSC. If a disturbance exceeds the planned/recognized/"prospective" MSSC value, it is outside the definition of MSSC and should not be subject to compliance evaluation. The requirement for a prospective MSSC is for the MSSC be used for planning purposes, not for real-time operations, even though it is used in such operations. MSSC is not a defined term in the NERC Glossary but work is in progress under NERC Project 2010-14.1 to develop a definition of MSSC. Therefore, it would not be in the best interest of the IDT in providing this interpretation to attempt to describe or define MSSC. LGE and KU Services recommends all language related to the IDT's explanation of MSSC be deleted from Response 1. Also, the language explaining the "Compliance and reporting category" and "Reporting only category" appears to be outside the inquiry of Question 1 and is suggested for deletion. LGE and KU Services suggests Response 1 be reduced to simply the first sentence of the response as it clearly answers Question 1: "The IDT agrees that the Disturbance would be excluded from compliance."

No

The meaning and use of the adjectives "pre-acknowledged" and "dynamically allocated" in description of RSG in Response 2 seem to be unnecessary, confusing and beyond the scope of Question 2. As stated in Response 2, there is a NERC Glossary definition of RSG and that is the subject of Question 2 – not the applicability of R5 to organizational variations of RSGs. The IDT has referenced a "Technical Document" that has not been included in the posting. The content therefore of the Technical Document is unknown. LGE and KU Services suggests Response 2 be reduced to only the language used in the "In summary,...." portion of the response as it clearly answers Question 2, edited as follows: "The Standard was written to provide RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period."

Yes

Individual

Cheryl Moseley

Electric Reliability Council of Texas, Inc.

ISO SRC

No

ERCOT agrees with the SRC comments. However, in addition to the SRC comments, ERCOT offers the following: ERCOT does not agree with additional details in the section that attempts to provide clarification. See the two excerpts below: Quote from Additional Compliance Information section: "To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC). An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition." There should be a period after the word "reported" and the phrase "to allow the ERO to help ensure that it is not a continuing condition." should be struck and removed. Quote from Additional Compliance Information section: "The Reporting only category is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC." The entire last sentence should be struck and removed. BA's are the functional entities responsible for coordinating with RC's, other BAs, TOPs, and GOPs to determine if a common mode failure requires a different MSSC. The ERO (NERC) is an oversight entity responsible for developing reliability standards and monitoring and enforcing compliance with those standards. It is not a functional entity. As such, it has no role in functional responsibilities, including the establishment of single contingencies and

operating to respect such contingencies in accordance to the applicable NERC standards and requirements. Accordingly, it is inappropriate for the interpretation to suggest, either directly or indirectly, that the ERO is in a position to monitor contingencies on the system, common mode or otherwise, to determine if such reoccurrences warrant consideration of multiple contingencies as a single contingency that could serve as an areas MSCC. There is explicit language in the interpretation that places the ERO in this role. Because this exceeds the scope of the ERO's functions and authority the interpretation must be revised to remove the problematic language. The above revisions are intended to address this issue, and ERCOT respectfully suggests the SDT make the suggested deletions.

Yes

ERCOT agrees with the SRC comments.

Yes

ERCOT agrees with the SRC comments.

Individual

Brett Holland

Kansas City Power & Light

Yes

Yes

Yes

Consideration of Comments

Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group Project 2009-19

The Project 2009-19 Drafting Team thanks all commenters who submitted comments on the proposed Interpretation of BAL-002-0 (R4, R5, and Section D 1.4) for the Northwest Power Pool Reserve Sharing Group. The interpretation was posted for a 45-day public comment period from July 25, 2012 through September 4, 2012. Stakeholders were asked to provide feedback on the interpretation and associated documents through a special electronic comment form. There were 25 sets of comments, including comments from approximately 96 different people from approximately 56 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Of those responders that disagreed with the interpretation, the majority questioned the use of the “Additional Compliance Information” in providing an interpretation of the requirements. The IDT explained that the NERC BOT specifically allowed the use of the reference materials in developing this interpretation. The IDT further explained that the NERC BOT recognized that in the conversion of NERC Policies to Version 0 standards, critical information was placed in sections outside of the requirements themselves and that strict construction policy in the case of the DCS standard was not consistent with the standard itself.

A few of the responders questioned how an RSG was to respond and the amount of time allowed to respond. The IDT explained that the clarification requested by NWPP was not about how an RSG was to respond or the amount of time allowed but instead focused on under what conditions could a Disturbance be excluded for compliance evaluation.

Some responders felt that the terms “pre-acknowledged RSGs” and “dynamically allocated RSGs” were not defined and therefore should not be used. The IDT explained that the terms “pre-acknowledged” and “dynamic” were used in the common English terms to be an RSG that is “recognized ahead of time rather than an after-the-fact”. And an RSG that is used on an on-call basis and thus its responding members are “not static”, respectively.

A few responders questioned why the rules were different for an RSG. The IDT explained that a “pre-acknowledged RSG” knows who is participating and who is not. However, a “dynamically allocated RSG” operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate.

A few responders questioned which version of the BAL-002 (BAL-002-0 or BAL-002-1) this interpretation would apply to. The IDT explained that although the interpretation was requested for BAL-002-0 it would apply to BAL-002-1 as well.

All comments submitted may be reviewed in their original format on the standard's [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 Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.¹

¹ The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

1. Do you agree with Response 1 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language..... 10
2. Do you agree with Response 2 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language..... 25
3. Do you agree with Response 3 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language..... 31

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X
	Additional Member	Additional Organization	Region	Segment	Selection								
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10									
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2									
3.	Greg Campoli	New York Independent System Operator	NPCC	2									
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1									
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1									
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10									
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5									
8.	Kathleen Goodman	ISO - New England	NPCC	2									
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1									
10.	Michael Lombardi	Northeast Utilities	NPCC	1									

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
11. Randy MacDonald		New Brunswick Power Transmission	NPCC	9										
12. Bruce Metruck		New York Power Authority	NPCC	6										
13. Lee Pedowicz		Northeast Power Coordinating Council	NPCC	10										
14. Robert Pellegrini		The United Illuminating Company	NPCC	1										
15. Si-Truc Phan		Hydro-Quebec TransEnergie	NPCC	1										
16. David Ramkalawan		Ontario Power Generation, Inc.	NPCC	5										
17. Michael Jones		National Grid	NPCC	1										
18. Brian Robinson		Utility Services	NPCC	8										
19. Silvia Parada Mitchell		NextEra Energy, LLC	NPCC	5										
20. Donald Weaver		New Brunswick System Operator	NPCC	2										
21. Michael Schiavone		National Grid	NPCC	1										
22. Wayne Sipperly		New York Power Authority	NPCC	5										
23. Ben Wu		Orange and Rockland Utilities	NPCC	1										
24. Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC	3										
2.	Group	Terry Bilke	ISO-RTO Standards Review Committee			X								
Additional Member		Additional Organization	Region	Segment Selection										
1. Ben Li		IESO	NPCC	2										
2. Steve Meyers		ERCOT	ERCOT	2										
3. Greg Campoli		NYISO	NPCC	2										
4. Ali Miremadi		CAISO	WECC	2										
5. Charles Yeung		SPP	SPP	2										
6. Kathleen Goodman		NEISO	NPCC	2										
7. Stephanie Monzon		PJM	RFC	2										
3.	Group	Ben Engelby	ACES Power Marketing Standards Collaborators							X				
Additional Member		Additional Organization	Region	Segment Selection										
1. Megan Wagner		Sunflower Electric Power Corporation	SPP	1										
4.	Group	Pablo Onate	El Paso Electric		X		X		X	X				
Additional Member		Additional Organization	Region	Segment Selection										
1. Dennis Malone		El Paso Electric	WECC	1										
2. Tracy Van Slyke		El Paso Electric	WECC	3										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3.	David Hawkins	El Paso Electric	WECC 5										
4.	Tony Soto	El Paso Electric	WECC 6										
5.	Group	Greg Rowland	Duke Energy	X		X		X	X				
Additional Member Additional Organization Region Segment Selection													
1.	Doug Hils	Duke Energy	RFC 1										
2.	Lee Schuster	Duke Energy	FRCC 3										
3.	Dale Goodwine	Duke Energy	SERC 5										
4.	Greg Cecil	Duke Energy	SERC 6										
6.	Group	David Dockery	Associated Electric Cooperative Inc - JRO00088	X		X		X	X				
Additional Member Additional Organization Region Segment Selection													
1.	Central Electric Power Cooperative		SERC 1, 3										
2.	KAMO Electric Cooperative		SERC 1, 3										
3.	M & A Electric Power Cooperative		SERC 1, 3										
4.	Northeast Missouri Electric Power Cooperative		SERC 1, 3										
5.	N.W. Electric Power Cooperative, Inc.		SERC 1, 3										
6.	Sho-Me Power Electric Cooperative		SERC 1, 3										
7.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				
Additional Member Additional Organization Region Segment Selection													
1.	James	Murphy	WECC 1										
2.	Fran	Halpin	WECC 5										
3.	Erika	Doot	WECC 3, 5, 6										
8.	Group	Robert Rhodes	SPP Standards Review Group		X								
Additional Member Additional Organization Region Segment Selection													
1.	C. J. Brown	Southwest Power Pool	SPP 2										
2.	Ron Gunderson	Nebraska Public Power District	MRO 1, 3, 5										
3.	Tiffany Lake	Westar Energy	SPP 1, 3, 5, 6										
4.	Heath Martin	Southwest Power Pool	SPP 2										
5.	Terry Oxandale	Southwest Power Pool	SPP 2										
6.	Mahmood Safi	Omaha Public Power District	MRO 1, 3, 5										
7.	Katie Shea	Westar Energy	SPP 1, 3, 5, 6										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Jason Smith	Southwest Power Pool	SPP 2										
9.	Carl Stelly	Southwest Power Pool	SPP 2										
10.	Bryan Taggart	Westar Energy	SPP 1, 3, 5, 6										
9.	Group	Gerald Beckerle	SERC Operating Committee Standards Review Team	X	X	X		X	X				X
Additional Member Additional Organization Region Segment Selection													
1.	Stuart Goza	TVA	SERC 1, 3, 5, 6										
2.	Melinda Montgomery	Entergy	SERC 1, 3, 6										
3.	Oliver Burke	Entergy	SERC 1, 3, 6										
4.	Wayne Van Liere	LGE-KU	SERC 3										
5.	Marie Knox	MISO	SERC 2										
6.	Tim Hattaway	PowerSouth	SERC 1, 5										
7.	Ronnie Douglas	Electric Energy, Inc	SERC 5										
8.	Brad Young	LGE-KU	SERC 3										
9.	Steve Corbin	SERC	SERC NA										
10.	Pat Huntley	SERC	SERC NA										
11.	Robert Thomasson	Big Rivers Electric Corp	SERC 1, 3, 5										
12.	Ronnie Douglas	Electric Energy	SERC 1, 3, 5										
10.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
11.	Individual	Michael Falvo	Independent Electricity System Operator		X								
12.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
13.	Individual	Thad Ness	American Electric Power			X		X	X				
14.	Individual	Oliver Burke	Entergy Services, Inc.	X		X		X	X				
15.	Individual	John Appel	Public Utility District #1 of Chelan County	X		X		X	X			X	
16.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
17.	Individual	Carter Edge	SERC										X
18.	Individual	linda Horn	Wisconsin Electric Power Company	X		X		X					
19.	Individual	Greg Travis	Idaho Power Co.										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	XX				
21.	Individual	Anthony Jablonski	ReliabilityFirst										X
22.	Individual	Maggy Powell	Exelon Corporation	X		X		X	X				
23.	Individual	Brent Ingebrigtsen	LG&E and KU Services Company			X							
24.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
25.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Supporting Comments of "Entity Name"
Public Utility District #1 of Chelan County	Chelan PUD supports the interpretation of BAL-002-0 on behalf of the NWPP.
Electric Reliability Council of Texas, Inc.	ISO SRC
Wisconsin Electric Power Company	We are supporting the comments of MISO.

1. Do you agree with Response 1 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation, the majority questioned the use of the “Additional Compliance Information” in providing an interpretation of the requirements. The IDT explained that the NERC BOT specifically allowed the use of the reference materials in developing this interpretation. The IDT further explained that the NERC BOT recognized that in the conversion of NERC Policies to Version 0 standards, critical information was placed in sections outside of the requirements themselves and that strict construction policy in the case of the DCS standard was not consistent with the standard itself.

A few of the responders questioned how an RSG was to respond and the amount of time allowed to respond. The IDT explained that the clarification requested by NWPP was not about how an RSG was to respond or the amount of time allowed but instead focused on under what conditions could a Disturbance be excluded for compliance evaluation.

A few responders referenced ALR 2-5 and stated that this should be carried forward in the future. The IDT explained that this interpretation request was not a question about ALR 2-5. What NWPP asked was if there were two contingencies at the same time, does the standard relieve them of the responsibility to respond in the given time frame. To paraphrase the IDT response, “if a BA experiences two simultaneous contingencies where total output was greater than the BAs MSSC, the BA must respond but will not be responsible to comply with the strictures of the requirement.”

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative Inc - JRO00088	No	Remove: The final paragraph beginning with "The Performance Standard Reference document initially included..."Rationale: A text-search of BAL-002-0, downloaded from the NERC website, fails to yield any instances of the word “dynamic”, meaning that it appears nowhere within the four-corners of the BAL-002-0 Standard. Responsible Entities are subject only to the Standard’s requirements as written and within its Effective Dates 4/1/2005 to 8/5/2010, when BAL-002-1 effectively replaced it. NERC’s BOT Approved August 2, 2006 filing with The Commission appears to contain the

Organization	Yes or No	Question 1 Comment
		oldest copy of FERC approved NERC Glossary of Terms Used in Reliability Standards. It contains no instances of the word “dynamic” that correspond in any way to Reserve Sharing Group membership, although “Reserve Sharing Group” and “Reportable Disturbance” are defined within that document. Although the SDT asserts the augmented concept of RSG dynamic membership, those references within this interpretation should be stricken because the “dynamic membership” concept clearly does not exist within the “four-corners of the Standard” which was balloted and approved by industry stakeholders. Instead BAL-002-0 wording indicates that each RSG can establish its own guidance, necessary to comply with the Requirements. Requirement R2 provides each Reserve Sharing Group the flexibility concerning its policies governing how it collectively fulfills its responsibility to meet Requirements R3, R4, R5 and R6. However Requirement R5’s parenthetical does appear to provide some governance concerning a BA’s reporting within a Reserve Sharing Group when they do not call for reserve activation from its other members, that they are subject to individually reporting their performance in responding to that event. (In either case of reporting per R5 parenthetical, the RSG’s collectively-committed units’ spinning-mass and short-term governor response would have fulfilled the reliability objective of this Standard, unless the Reportable Disturbance’s magnitude was much greater than anticipated by the RSG in its entirety.)
Response: Under normal circumstances Associated Electric Cooperative Inc would be correct that only the stated requirements within the four corners of a standard can be referenced in an interpretation. In this case however, the NERC Board of Trustees specifically allowed the Interpretation Drafting Team to make use of reference materials that were created for the original NERC Policy but that in the conversion from NERC Policy to Version 0 standards those materials were placed in sections outside of the requirements themselves. The BOT recognized that strict constructionism in the case of the DCS standard was not consistent with the standard itself and those who drafted the standard.		

Organization	Yes or No	Question 1 Comment
Response 1 deals with the issue of excluding a Disturbance that exceeds the most severe single Contingency of a BA or an RSG. Response 1 does not deal with governance. A group of BAs can form an RSG (please note that despite the fact that RSG is a defined term, it does not mean that all RSGs are the same) and decide how to allocate and measure the service it will provide. However, as the cited reference (Performance Standards Guidelines) states (chapter 6, Reporting) “Where RSGs exist, the Regional Reliability Council is to decide either to report these on a BA basis or on an RSG basis.” Thus it is clearly not up to the RSG to make that decision about reporting. If the reporting were left to the RSGs then the standard would be a fill-in-the-blanks standard. The RSG would be allowed after-the-fact to decide whether or not two independent losses would be counted as a reason for not reporting. Such an approach would place the system at risk – and the original drafters of that BAL-002 recognized the need to make clear that to take advantage of this benefit, the dynamic RSG (not all RSGs just those that BAs make use of on an as needed basis) must have permission from their Region to address such events on a composite basis. The question raised by NWPP was not about allowing RSGs to respond, the question was about which conditions would exclude a disturbance that exceeded the MSSC of the BA or RSG. It is clear that for a BA any set of non-common mode contingencies that exceed its MSSC would be excluded. For an RSG that has a variable participation, that situation is by definition unclear. Since BA(1) may lose a resource equal to its MSSC and not call for reserve sharing and fail to comply with the standard, however, unknown to BA(1) is the fact that BA(2) also lost a resource at the same time. BA (2) also did not call for reserve sharing and failed to comply. However, after the fact the RSG observes the situation that as a group they would be permitted to exclude the “composite disturbance”. The original drafters recognized that fact and precluded that situation by requiring that the Regions decide which MSSC to accept for a BA and which RSGs are permitted to treat themselves as a single BA. The standard was written to serve reliability and not as a means to avoid responding to disturbances. The BOT recognized that fact and allowed the IDT to respond to the NWPP question on the basis of what the drafters meant as indicated by all available reference material and not be limited by the 4 wall of the requirements.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.

Organization	Yes or No	Question 1 Comment
Response: The interpretation was not based entirely on the requirements of BAL-002-0, but also on the Additional Compliance Information section and other reference material (See response to AECI's question 1 comment) as allowed by the BOT.		
SERC	No	The interpretations process is not an appropriate mechanism to address a compliance monitoring and enforcement issue. Further, the words in the requirements do not support the interpretation, no matter how much the interpretation reflects how the industry and ERO have historically approached the Disturbance Control Standard. The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Specifically, Requirement 1 requires each Balancing Authority to have access to and/or operate Contingency Reserve to respond to Disturbances. Prior to penalties and sanctions under Section 215, the consequence of failing DCS was to require an increase in contingency reserves. This is the “compliance evaluation” referred to under Section D. The expectation is that Balancing Areas respond to the loss of resources regardless of magnitude to restore ACE and minimize the risk to reliable operation of being “out of balance”. There was recognition, however, that interconnected operations increased the reliability of the grid by reducing the consequences of a single area being out of balance at any given time and thus allowed the collective greater utilization of installed capacity to serve load rather than retain it as contingency reserves. Thus, the concept of “most severe single contingency” (MSSC) as a criterion against which to require additional contingency reserve was employed and for large contingencies may require more time to respond. Fifteen minutes is a "benchmark" time-frame that is reasonable to expect a Balancing Area to recover from a credible contingency. There is nothing magical about that time (it used to be 10 minutes), but the BA should not "lean" on the system longer than is

Organization	Yes or No	Question 1 Comment
		necessary regardless of the magnitude. Performance outside this benchmark can only be determined by an inspection of the facts and circumstances of each instance. All Balancing Authorities and Reserve Sharing Groups are required to review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies. The NERC glossary defines Contingency as the “unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element”. Thus, the compliance action or inaction ("decline to pursue") with respect to the performance of an entity against the stated requirements in the standard is a matter of the CMEP and should not be addressed through the standards interpretations process. Compliance activity should be based on the facts and circumstances of each case measured against the performance requirements of the standard. Standards (including interpretations) are for describing the behaviors and actions of registered entities necessary for the reliable planning and operation of the bulk power system not the Compliance Enforcement Authority. Informed and expert discretion rather than this interpretation (which requires inaction) is a better answer for the Reliability Assurer. Further, ALR 2-5 has a stated purpose as a measure of how much risk a system is exposed to for extreme or unusual contingencies (Simultaneous Contingencies - Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation). The results of ALR 2-5 are expected to help validate current contingency reserve requirements and document how often these “extreme or unusual” contingencies occur. These activities should

Organization	Yes or No	Question 1 Comment
		continue.
Response: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Prior to penalties and sanctions under Section 215, the consequence of failing DCS was to require an increase in contingency reserves. This is the “compliance evaluation” referred to under Section D. Thus, the concept of “most severe single contingency” (MSSC) as a criterion against which to require additional contingency reserve was employed and for large contingencies may require more time to respond. This is not correct. MSSC was used to recognize the fact that the Reserve obligation was to include not simply the largest “generator” but that the largest common mode failure must also be covered. That included single interchange schedules that could be curtailed instantaneously. However, MSSC varies as a function of the assets operating at any given time. Thus the MSSC may be 1500 when a BA’s 1500 MW nuclear unit is running, but then becomes 500 when that nuclear unit is off, and the BAs next largest unit is a 500 MW generator. The time response was not addressed in the NWPP question or in the interpretation. The question NWPP asked was what is excluded from compliance penalty by the DCS standard. It is clear that the standard held BAs to meet the DCS requirement when they had a contingency. It is also clear that contingencies less than 80% of the MSSC were not mandated to be “reported”. The drafters of the standard did not intend that contingencies below 80% did not require action, but the consequence of the non-reporting exception provided that situation. ALR 2.5 is not in question. What NWPP asked was if there are two contingencies at the same time, does the standard relieve them of the responsibility to respond in the given time frame. To paraphrase the IDT response, “if a BA experiences two simultaneous contingencies who total output was greater than the BAs MSSC, the BA must respond but will not be responsible to comply with the strictures of the requirement.” SERC’s contention regarding the Reliability Assurer may or may not be true, but the IDT is tasked with interpreting what the standard		

Organization	Yes or No	Question 1 Comment
in question says. SERC is welcome to submit a SAR to change the standard.		
ReliabilityFirst	No	ReliabilityFirst votes in the Negative for the Interpretation of BAL-002 since ReliabilityFirst believes the drafted interpretation to Question 1 incorrectly expands on the language in Requirement R4 and incorrectly attempts to explain how to comply with the Requirement. If a reportable disturbance occurs (i.e. contingencies that are greater than or equal to 80% of the most severe single Contingency) and is greater than the most severe single Contingency, ReliabilityFirst questions why an entity would not be required to meet the Disturbance Recovery Criterion. Nowhere within the requirements are there exceptions for Reportable Disturbance greater than the most severe single Contingency. Based on R4, the applicable entity “...shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances”. For example, if an entity failed to meet the meet the Disturbance Recovery Criterion for a disturbance equaling 110% of their most severe single Contingency, they would potentially be found non-compliant. In addition, ReliabilityFirst does not believe the quasi definition of “Simultaneous Contingencies” within the “Additional Compliance Information” is not enforceable since it is not a Reliability Requirement, and is not even a NERC Defined term.
Response: Regarding RFC’s concern about expanding the language of the requirement, the IDT refers them to the IDT’s response to AEC Inc. An IDT is not formed to respond to why a standard mandates what it mandated; the IDT is only obligated to interpret what the drafters meant by the mandated requirement.		

Organization	Yes or No	Question 1 Comment
Regarding Excludable Disturbances RFC is correct that exclusions are not in the requirement, but as explained in the AEC Inc response the IDT was permitted to use other reference material. RFC is referred to the cited reference (Performance Standards Reference Guidelines - http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf) Reporting Section items a.2. And a.3. That specifically references Excludable Disturbances. According to the requirement and the associated reference materials the IDT concludes that a BA cannot be held non-compliant with a disturbance that is 110% of their MSSC. The standard specially excludes such disturbances from compliance. Regarding Simultaneous Contingencies, the IDT would simply refer to the BOT allowance for the IDT to include such reference material.		
LG&E and KU Services Company	No	The IDT's explanation of MSSC may be unnecessary and confusing, especially statements such as: "MSSC is a variable that the BA knows and operates to in real time." "Thus the BA knows its MSSC which can vary from hour to hour and minute to minute." "To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC)." "In the absence of an identifiable/specific reason, which is recognized by the BA in advance, the real-time MSSC should not exceed the prospective MSSC. Unless such an abnormal situation exists, all evaluations of DCS compliance must be based on the prospective MSSC value. The IDT needs to be very clear with any language suggesting that the real-time MSSC can exceed the planned/recognized/"prospective" MSSC. If a disturbance exceeds the planned/recognized/"prospective" MSSC value, it is outside the definition of MSSC and should not be subject to compliance evaluation. The requirement for a prospective MSSC is for the MSSC be used for planning purposes, not for real-time operations, even though it is

Organization	Yes or No	Question 1 Comment
		used in such operations. MSSC is not a defined term in the NERC Glossary but work is in progress under NERC Project 2010-14.1 to develop a definition of MSSC. Therefore, it would not be in the best interest of the IDT in providing this interpretation to attempt to describe or define MSSC. LGE and KU Services recommends all language related to the IDT's explanation of MSSC be deleted from Response 1. Also, the language explaining the "Compliance and reporting category" and "Reporting only category" appears to be outside the inquiry of Question 1 and is suggested for deletion. LGE and KU Services suggests Response 1 be reduced to simply the first sentence of the response as it clearly answers Question 1: "The IDT agrees that the Disturbance would be excluded from compliance."
Response: Thank you, the IDT agrees that it is necessary to be "very clear", hence the explanation. To use the proposed straight forward answer would leave others asking what is meant. Since your answer and our answer agree, the IDT will retain the explanation.		
Electric Reliability Council of Texas, Inc.	No	ERCOT agrees with the SRC comments. However, in addition to the SRC comments, ERCOT offers the following: ERCOT does not agree with additional details in the section that attempts to provide clarification. See the two excerpts below: Quote from Additional Compliance Information section: "To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC). An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition." There should be a period after the word "reported" and the phrase "to allow the ERO to help ensure

Organization	Yes or No	Question 1 Comment
		that it is not a continuing condition.” should be struck and removed. Quote from Additional Compliance Information section: “The Reporting only category is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC.”The entire last sentence should be struck and removed. BA’s are the functional entities responsible for coordinating with RC’s, other BAs, TOPs, and GOPs to determine if a common mode failure requires a different MSSC. The ERO (NERC) is an oversight entity responsible for developing reliability standards and monitoring and enforcing compliance with those standards. It is not a functional entity. As such, it has no role in functional responsibilities, including the establishment of single contingencies and operating to respect such contingencies in accordance to the applicable NERC standards and requirements. Accordingly, it is inappropriate for the interpretation to suggest, either directly or indirectly, that the ERO is in a position to monitor contingencies on the system, common mode or otherwise, to determine if such reoccurrences warrant consideration of multiple contingencies as a single contingency that could serve as an areas MSCC. There is explicit language in the interpretation that places the ERO in this role. Because this exceeds the scope of the ERO’s functions and authority the interpretation must be revised to remove the problematic language. The above revisions are intended to address this issue, and ERCOT respectfully suggests the SDT make the suggested deletions.
Response: The IDT is responsible to interpret what the requirement meant. The idea of having a requirement for reporting excludable disturbances just for the sake of reporting does not make sense. The reason for reporting was to ensure that reliability entities do not take advantage of the exclusion. At the time the standard was written the NERC Performance Subcommittee		

Organization	Yes or No	Question 1 Comment
(translated here to be the ERO) was to collect and evaluate those instances.		
ISO-RTO Standards Review Committee	Yes	We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below: "Most Severe Single Contingency (MSSC) - this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction." We do not agree the term "firm transaction". The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA's resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction. Further, the term "firm transaction" is subject to debate as to whether the firmness is in the energy component or in the transmission service component. If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word "firm" from the clarification section.
Response: Thank you for your affirmative response and clarifying comment.		
ACES Power Marketing Standards Collaborators	Yes	We conceptually agree with the position of the interpretation. However, we believe that the current response expands issues that were not raised in the original question. One example is that the "MSSC value at any given time may be more or less than the annually identified prospective MSSC" is

Organization	Yes or No	Question 1 Comment
		contradictory to the interpretation. How could the MSSC value could ever be higher than the list of candidate MSSCs identified in the annual review. Also, in the “reporting only” category in response 1, the IDT incorrectly characterizes that the ERO would have authority or the information to alert the BA that two (or more) contingencies must be considered as a single event and thus considered as the MSSC. The ERO does not determine the MSSC, the BA or RSG makes that determination. For simplicity and clarity, we recommend that the interpretation state: Disturbances greater than MSSC are excluded from the compliance calculation, based on the additional compliance information section of BAL-002-0. The IDT could strike everything following this statement from the interpretation and would convey the same message in a more clear and concise manner.
Response: Thank you for your affirmative response and clarifying comment. An MSSC can be higher if the BA expanded its boundaries, or if the BA made an interchange schedule larger than expected.		
El Paso Electric	Yes	El Paso Electric (EPE) generally supports the first interpretation proposed by the IDT but is concerned with the language immediately following "To be clear..." because it does not acknowledge the fact that many BAs have placed responsibility in the hands of a RSG. The interpretation states that "...a BA is responsible for the MSSC at all times...". EPE believes that this responsibility should be shared with a RSG, where appropriate. EPE would be more comfortable with an interpretation that read "To be clear a BA or RSG, as applicable, is responsible for the MSSC at all times..."
Response: The issue in question depends on the type of RSG involved. The BA is responsible. However, if a BA makes use of an RSG then based on the rules of the RSG it could be the BA, it could be the RSG or it could be some combination. The IDT believes that its response properly allows for any of the above. Based on the governance of the RSG and the Region it is in.		
Duke Energy	Yes	We suggest that there should be a SAR to define the terms MSSC and

Organization	Yes or No	Question 1 Comment
		"excludable disturbance" add them to the NERC Glossary.
Response: Thank you for your affirmative response and clarifying comment. There –presently is a project under development to address the issue you have brought forward (Project 2010-14.1 BARC – Reserves).		
SPP Standards Review Group	Yes	This interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
SERC Operating Committee Standards Review Team	Yes	The SERC OC Standards Review Group gladly presents the following comments. The SERC OC Standards Review Group agrees only with the interpretation portion of the response. The Group strongly disagrees there is a need for the additional explanation of the interpretation. The explanation presents more confusion and questions around the Standard. The simple interpretation is very clear and concise.
Response: Thank you for your affirmative response and clarifying comment.		
Independent Electricity System Operator	Yes	We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below:"Most Severe Single Contingency (MSSC) - this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction."We do not agree the term "firm transaction". The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA's resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction.

Organization	Yes or No	Question 1 Comment
		Further, the term “firm transaction” is subject to debate as to whether the firmness is in the energy component or in the transmission service component.If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word “firm” from the clarification section.
Response: Thank you for your affirmative response and clarifying comment. See our response to SRC.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
Exelon Corporation	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Yes	
Entergy Services, Inc.	Yes	

2. Do you agree with Response 2 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation the majority felt that the terms “pre-acknowledged RSGs” and “dynamically allocated RSGs” were not defined and therefore should not be used. The IDT explained that the terms “pre-acknowledged” and “dynamic” were used in the common English terms to be an RSG that is “recognized ahead of time rather than an after-the-fact”. And an RSG that is used on an on-call basis and thus its responding members are “not static”, respectively.

A few responders questioned why the rules were different. The IDT explained that a “pre-acknowledged RSG” knows who is participating and who is not. However, a “dynamically allocated RSG” operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate.

Organization	Yes or No	Question 2 Comment
Duke Energy	No	It's not clear what the drafting team is saying, particularly the reference to “dynamic allocation of membership”. What's the difference between pre-acknowledged RSGs and dynamically allocated RSGs, and why are the exclusion rules different?
Response: RSG as it pertains to structure is not a common entity. Some RSG are designed to be “on-call” and hence have a dynamic membership. The aforementioned RSG could consist of a pool of 20 BAs, but have 2 (of 20) members who are responding for one disturbance and 15 (of 20) for the next. While the pool of BAs may be fixed, based on the governance of the particular RSG, the obligations of the RSG are allocated only to those who agree to participate for the given disturbance. Of course other RSGs may operate as a unit for all disturbances that occur and thus all pool members are obligated for all disturbances (in effect they become a single BA for purposed of DCS).		

Organization	Yes or No	Question 2 Comment
The exclusion is really the same, what is different is in deciding who is to be counted in multiple disturbances (note this difference is small since the probability of one BA in an RSG having a disturbance at the same as another BA having an independent disturbance is low). But the fact remains that weather conditions could and do span multiple BAs and can result in such simultaneous disturbances (although it is more likely that one BA would be more likely to experience such independent disturbances.) For a pre-acknowledge RSG, one knows exactly who is participating and who is not. In an RSG that operates only on an on-call basis (i.e. a dynamically-allocated RSG) one cannot determine who is responsible and who is not UNTIL everyone who wants to participate has communicated their participation.)		
SERC Operating Committee Standards Review Team	No	The SERC OC Standards Review Group feels the interpretation and clarification are both very confusing, thus raising numerous other questions. The use of the words “pre-acknowledged RSGS” and “dynamic allocated RSGS” appear to be new terms introduced in the response. Also, a reference to a Technical Document is made in the response. The Group is unsure of what Technical Document the IDT is referring. Nor does the Group understand if such reference to the Technical Document is an agreement with such document by the IDT or if the Technical Document is referenced as to be included in the response and subject to being opened and the processes and procedures of such document being made part of a compliance audit.
Response: The Technical document can be found at the following link. http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf The BOT recognized that the creation of DCS was supported by other materials such as Reference Documents and a Frequently Asked Questions. These documents hold the key to what was meant by the DCS requirements and are important in any interpretation.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided. For example, it is not clear to us exactly what “pre-acknowledged” or “dynamic” means in regards to Reserve Sharing Groups. These terms are not found anywhere within the standard itself, nor are they commonly used to describe or qualify Reserve Sharing Groups.

Organization	Yes or No	Question 2 Comment
Response: The terms “pre-acknowledged” and “dynamic” are used in the common English terms to be an RSG that is “recognized ahead of time rather than after-the-fact”, and an RSG that is used on an on-call basis and thus its responding members are “not static”, respectively.		
SERC	No	See answer to question #1.
Response: See response to Question #1		
LG&E and KU Services Company	No	The meaning and use of the adjectives “pre-acknowledged” and “dynamically allocated” in description of RSG in Response 2 seem to be unnecessary, confusing and beyond the scope of Question 2. As stated in Response 2, there is a NERC Glossary definition of RSG and that is the subject of Question 2 - not the applicability of R5 to organizational variations of RSGs. The IDT has referenced a “Technical Document” that has not been included in the posting. The content therefore of the Technical Document is unknown. LGE and KU Services suggests Response 2 be reduced to only the language used in the “In summary,....” portion of the response as it clearly answers Question 2, edited as follows: "The Standard was written to provide RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period."
Response: Question 2 is about exclusions for RSGs. The reference material (http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf) makes the distinction about whether or not the Region agrees ahead of time (pre-acknowledged) or whether or not there is an known MSSC for the RSG (if the responders are dynamically joining or not). Thank-you for your suggestion, but given the responses to the interpretation, the IDT will retain the explanation.		

Organization	Yes or No	Question 2 Comment
ACES Power Marketing Standards Collaborators	Yes	We largely agree with the interpretation. However, we want to point out that the concept of pre-acknowledged RSGs have disincentivized Adjacent Balancing Authorities (not in a pre-acknowledged RSG) to provide reserves in less than 10 minutes even if they are capable. If an Adjacent Balancing Authority provides emergency energy in an amount that exceeds its own MSSC with a ramp less than 10 minutes and fails to recover its ACE from within 15 minute of the initial disturbance, the Adjacent BA may be found non-compliant despite the fact the it provided the appropriate reliability assistance. Compliance should not disincentivize actions that ensure reliability.
Response: The IDT agrees that the terms of an agreement may influence a BA on agreeing to participate in a given type of RSG. But the responsibility and allocation of penalties is a governance matter defined with the dictates of the agreement the BA signs, it is not a matter for the requirement. This interpretation neither incents or dis-incents making an agreement of any kind. If an entity does not agree with the rules of a proposed RSG agreement they are not obligated by this interpretation to sign that agreement.		
El Paso Electric	Yes	EPE generally supports the second interpretation by the IDT but requests that IDT clarify the scope of compliance evaluations for BAs who are part of a RSG and experienced a reportable event, without regard to whether any individual BA member of the RSG requested assistance. If a RSG determines that the group as a whole complied with CPS then there should be no need for any individual BA review or reporting under R5, without regard to whether the BA called for reserve activation from other RSG members, or not. The interpretation should include this clarification.
Response: This interpretation is based on the concept that BAs would submit “Reportable Disturbances”. These reports provide more than compliance information, they provide information on the state of responses. This information was deemed valuable to the Resources Subcommittee. Even in today’s environment there is a need to “self-report” non-compliance. The question raised by the NWPP is for a situation in which a BA is non-compliant with the DCS requirement but because of circumstances (explained in the Reference documents and in the Interpretation), the BA is excused from complying with the requirement (i.e. the disturbance is excludable). The decision for		

Organization	Yes or No	Question 2 Comment
exclusion should be easy but as indicated by some responses there are CEAs who say they would hold entities non-compliant for such events.		
SPP Standards Review Group	Yes	Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the SRC comments.
Response: Thank you for your affirmative response and clarifying comment.		
Associated Electric Cooperative Inc - JRO00088	Yes	Rationale: In our opinion, the IDT failed to answer Question #2, which could have been answered with a simple “Yes”. Instead, they appear to attempt legislating upon particulars of how all RSGs should structure portions of their policies under R2, by again referring to the concept of “dynamic membership”. Our understanding is that such expansion of Standard governance can only be done under SDT effort and subsequent industry approval through the ballot process. (See AECI’s earlier response to Question 1 above.)
Response: Thank you for your affirmative response and clarifying comment.		
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Entergy Services, Inc.	Yes	
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
ReliabilityFirst	Yes	
Exelon Corporation	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
ISO-RTO Standards Review Committee	Yes	

3. Do you agree with Response 3 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation the majority questioned which version of the BAL-002 (BAL-002-0 or BAL-002-1) this interpretation would apply to. The IDT explained that although the interpretation was requested for BAL-002-0 it would apply to BAL-002-1 as well.

A few responders objected to the wordiness of the response. The IDT explained that their intent was to encourage an understanding of the interpretation. The first two paragraphs were basically a restatement of the requirement and the last paragraph was the actual interpretation.

Organization	Yes or No	Question 3 Comment
Duke Energy	No	It's not clear what the drafting team is saying. Does "excluded from compliance evaluation" mean that R4 does not apply to Disturbances that exceed the MSSC for a BA or RSG? Does it matter if the RSG is pre-acknowledged or dynamically allocated? The drafting team's response to Question 2 seems to indicate that it does matter. We agree that DCS is not applicable for losses greater than the MSSC, and also that DCS compliance is not required for losses less than 80% of the MSSC (or lower if a lower threshold is adopted for DCS reporting). This interpretation is performed on BAL-002-0, but the current effective standard is BAL-002-1 as of 4-1-2012. If the interpretation is approved, what is its applicability to BAL-002-1? Under BAL-002-0 the default Disturbance Recovery Period could be adjusted to better suit the needs of an Interconnection (R4.2) and the default Contingency Reserve Restoration Period could be adjusted to better suit the reliability targets of the Interconnection (R6.2), both based on analysis approved by the NERC Operating Committee. This has been deleted from both requirements in BAL-002-1.

Organization	Yes or No	Question 3 Comment
Response: The IDT believes the interpretation is clear and that the Interpretation would apply to the current version as well as to the former version.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.
Response: See response to Question #1.		
SERC	No	See Response to question #1.
Response: See response to Question #1		
Exelon Corporation	No	Response 3 of the interpretation that requests clarification on the phrase “excluded from compliance evaluation” could be clearer. The first portion of the response gives the impression that the IDT is of the opinion that the obligation to comply with the DCS extends to events larger in magnitude than the MSSC. The paragraphs that follow go on to clarify that an event greater than the MSSC would not be required to recover ACE within 15 minutes, making compliance with the DCS not mandated in these instances. The latter (disturbances exceeding the MSSC being excluded from DCS compliance and 15 minute recovery) is consistent with practice and in line with the interpretation indicated by the NWPP. In order to more fully clarify the interpretation, the IDT should make clear that compliance with the DCS is not mandated for disturbances exceeding the MSSC.
Response: The first two paragraphs are meant as a restatement of the requirements. The last paragraph is the interpretation.		
ISO-RTO Standards Review Committee	Yes	It might be clearer if the reponse added the phrase [of the Disturbance Control Standard] after “loss shall be reported, but excluded from compliance evaluation”.

Organization	Yes or No	Question 3 Comment
		Following a large event, the BA would still be accountable for other standards (e.g. IRO standards)
Response: Thank you for your affirmative response and clarifying comment.		
ACES Power Marketing Standards Collaborators	Yes	We agree for the most part with this interpretation. However, we do have a few points we would like to address. We recommend striking the entire second paragraph because it is irrelevant. The standard does not say comply with DCS “for every reportable disturbance.” The key is whether a BA is required to recover ACE within 15 minutes for contingencies greater than MSSC, and that answer is no. The IDT should keep the interpretation simple. A recommendation for wording the interpretation: A BA is not required to recover ACE within 15 minutes for contingencies greater than MSSC, as stated in section 1.4 (“Additional Compliance Information”). We recommend that the IDT reduce the amount detail in the rationale and focus on the three questions in the request. The current draft of the interpretation is wordy, confusing and provides excessive details instead of answering the questions that were asked. Also, the IDT did not state that this interpretation would apply to BAL-002-1, which has been enforceable since 4/1/2012. If NERC is going to continue with the interpretation process for BAL-002, the interpretation should apply to both versions of the standard. Finally, we encourage NERC to consolidate standard projects. There are currently 10 standard projects under development for BAL standards. NERC should consider either a consolidation to a reduced amount of BAL projects or even a single project to cover all BAL issues in order to avoid duplication, overlap, inefficient use of resources and confusion.
Response: Thank you for your affirmative response and clarifying comment. The wordy explanation was meant to encourage an understanding of the interpretation. Given the overwhelming support that approach seems to have been effective.		

Organization	Yes or No	Question 3 Comment
The Interpretation would apply to the current version as well as to the former version. This is an interpretation not a standard development. There is a need to respond to this issue as soon as possible. The BAL project may or may not receive approval and to link that Project with this Interpretation would not be helpful to those waiting for this interpretation.		
Associated Electric Cooperative Inc - JRO00088	Yes	We agree with this summary determination. In addition, the August 2, 2006 NERC BOT approved, and subsequently FERC accepted Glossary definition for Reportable Disturbance clearly specified that the definition “not be retroactively adjusted in response to observed performance”, adding weight to this drafting-team’s response to Question 3. (FERC_Filing_Proposed_Reliability_Standards_Docket_RM06-16-000.pdf)
Response: Thank you for your affirmative response and clarifying comment.		
SPP Standards Review Group	Yes	Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Independent Electricity System Operator	Yes	(1) We generally agree with the proposed interpretation. However, we are not sure if this request fits well into NERC’s criteria for acceptance as a valid request since it appears that the requester asks specifically on the compliance implications and compliance elements. We suggest the interpretation drafting team (IDT) to evaluate whether or not the request is a valid one that seeks clarity on the requirements, rather than on the compliance aspects of the standard/requirements. If the IDT does assess that the questions are addressing a compliance issue, then we suggest the IDT to bring this to the attention of the Standards Committee for a determination of the appropriate means to address the questions.

Organization	Yes or No	Question 3 Comment
		(2) The IESO agrees with NERC's interpretation of BAL-002. However, we believe additional discussion and thought need to be applied to other Standards to ensure that no gaps or overlaps exist in both task execution and Standard application. Different Standards obligate Reliability Entities to fulfill certain tasks as it pertains to balancing: conditions. This includes: - o BAL- 002 outlines obligations to balance following Reportable Disturbances; - o EOP-002 outlines obligations to balance during Capacity and Energy Emergencies; and - o TOP-001 outlines obligations to balance during System Emergencies. All of these Standards have similarities but need interpretation to ensure consistent application. These interpretations are based on an understanding of the NERC Functional Model and upon clear statements in the purpose and requirement sections in the Standards. We believe that the objective of each of the Standards list above must be clarified to reduce confusion and support consistent application.
Response: Thank you for your affirmative response and clarifying comment. The IDT is not making a decision on a given compliance issue, it is simply providing an interpretation of what is meant by excludable disturbances. It is not within the purview of an IDT to address other issues outside the bounds of the proposed question. The IESO is encouraged to participate in Projects that address the above requirements or to submit a SAR to rectify their issues and concerns.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		

Organization	Yes or No	Question 3 Comment
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the SRC comments.
Response: Thank you for your affirmative response and clarifying comment.		
SERC Operating Committee Standards Review Team	Yes	NONE
El Paso Electric	Yes	No Comment.
Bonneville Power Administration	Yes	BPA is in support of BAL-002-0 Interpretation and has no comments or concerns at this time.
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
LG&E and KU Services Company	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 3 Comment
Entergy Services, Inc.	Yes	
ReliabilityFirst		ReliabilityFirst disagrees with the drafted interpretation. Regardless of the references to outside sources (the reserve requirement specified in R3.1 of BAL-002-0, the text of Section 1.4 of Part D of BAL-002-0, and the documented history of the development of BAL-002-0), compliance is to be assessed on a requirement by requirement basis. Requirement R4 requires that an applicable entity "...shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances". Clearly, there is no exception listed within the requirements for Reportable Disturbances greater than the most severe single Contingency.
Response: The IDT disagrees with your perception. In addition, the industry ballot indicates that the Industry does not agree with RFC's perception.		

END OF REPORT

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard	
Date submitted:	September 2, 2009
Date accepted:	September 2, 2009
Contact information for person requesting the interpretation:	
Name:	Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization:	Northwest Power Pool Reserve Sharing Group
Telephone:	503-445-1074
E-mail:	jerry.rust@nwpp.org
Identify the standard that needs clarification:	
Standard Number (include version number):	BAL-002-0
Standard Title:	Disturbance Control Performance
Identify specifically what requirement needs clarification:	
<u>Requirement Number and Text of Requirement:</u>	
B. Requirements	

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	
R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value. R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.	

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. *** Compliance may be demonstrated by either	

of the following two methods:

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

D. Compliance

1.4 Additional Compliance Information

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Clarification needed:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

- (1) although a Disturbance¹ that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
- (2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve

¹ Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

- (3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for “enough Contingency Reserve to cover the most severe single Contingency”) meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute “Reportable Disturbances.” See Section 1.4 of Part D of BAL-002-0 (where the “Additional Compliance Information” includes a definition of “Reportable Disturbance”).

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (see, e.g., Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that “An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.”)

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Response:

The Balancing Authority Controls Standard Drafting Team was originally assigned to provide

3353 Peachtree Road NE
Atlanta, GA 30326
www.nerc.com

a response to the interpretation request. The original interpretation failed to achieve a two-thirds approval from the industry. NERC appointed a new IDT to develop this interpretation. On July 24, 2012, the team provided the following response to the questions raised:

Question 1: Although a Disturbance² that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?

Response: The IDT agrees that the Disturbance would be excluded from compliance. The BAL-002 **Additional Compliance Information section** clearly states:

Simultaneous Contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

For clarity the IDT would like to explain the Team's basis concerning some of the terminology used.

Most Severe Single Contingency (MSSC) – this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction. Although Requirement R3.1 mandates an annual "review" that does not mean an annual value. Note that Requirement R3.1 determines a "prospective" MSSC. MSSC is a variable that the BA knows and operates to in real time. The largest operating generator is known and monitored by a BA. The largest known common mode failure is predefined for the BA; the largest single firm transaction is approved by the BA. Thus the BA knows its MSSC which can vary from hour to hour and minute to minute.

To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC).

An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition.

BAL-002 has two categories (1) Compliance and reporting (for Reportable Disturbances that must comply with the disturbance recovery criteria within the Disturbance Recovery Period) and (2) Reporting only (for specified disturbances and system conditions) events that are excluded from meeting Requirement R4

² Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

requirement.

The **Compliance and reporting category** is designed to be used to accumulate all DCS events that are subject to compliance to BAL-002 Requirement R4 (i.e. recover ACE within 15 minutes). These include all single assets as well as all pre-defined common mode failures. The standard originally created R_i (the average percent recovery for a Reportable Disturbance) as a measure of the quarterly compliance for Reportable Disturbances. Where all events greater than 80% were mandatory to report and those less than 80% were permitted to be reported (thus encouraging reporting smaller events).

The **Reporting only category** is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC.

The **Performance Standard Reference document** initially included with the DCS standard does states "Where RSGs exist, the Regional Reliability Council is to decide either to report on a BA basis or an RSG basis. If an RSG has dynamic membership then... required ...to report on a BA basis.

Question 2: With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?

Response: Requirement R5 is directed to RSGs, where RSG is defined in the NERC Glossary as:

A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

The standard provides flexibility to BAs regarding the use or non-use of RSGs (Requirement R1.1). Requirement R2 affords the members flexibility in how they organize themselves.

Requirement R1.1 allows, at the option of a BA, or RSG to take on all or part of the responsibilities that BAL-002 places on a BA. However, Requirement R5 allows a BA to “call for activation” of reserves [aka dynamic allocation of membership] moreover, there is no ad hoc recognition of such an RSG’s multiple contingencies since a contingency in one BA may or not be referred to the RSG, and the simultaneous contingency in another BA is unknown.

The Technical Document does allow for a pre-acknowledged RSG to report on a composite basis. It can be interpreted that such a pre-acknowledged RSG entity assumes all of the obligations and rights afforded to a single BA and in that case such an RSG would be afforded the same Exclusions as the Exclusions afforded a BA.

In summary, the interpretation is as follows:

- The Standard was written to provide pre-acknowledged RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a pre-acknowledged RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period.

The standard, while recognizing dynamically allocated RSGs, does NOT provide the members of dynamically allocated RSGs exclusions from DCS compliance evaluation on an RSG basis. For members of dynamically allocated RSGs, the exclusions are provided only on a member BA by member BA basis.

Question 3: Clarify the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Response: The **Additional Compliance Information section** clearly states:

Simultaneous contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the Most Severe Single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Although Requirement R3 does mandate that a BA or RSG activate sufficient Contingency Reserves to comply with DCS for every Reportable Disturbance, there is no requirement to comply with or even report disturbances that are below the Reportable Disturbance level. The averaging obligation does incent calculation and reporting of such lesser events.

If a Balancing Authority were to experience a Disturbance five times greater than its

most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency. Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.,* Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007)), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard	
Date submitted:	September 2, 2009
Date accepted:	September 2, 2009
Contact information for person requesting the interpretation:	
Name:	Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization:	Northwest Power Pool Reserve Sharing Group
Telephone:	503-445-1074
E-mail:	jerry.rust@nwpp.org
Identify the standard that needs clarification:	
Standard Number (include version number):	BAL-002-0
Standard Title:	Disturbance Control Performance
Identify specifically what requirement needs clarification:	
<u>Requirement Number and Text of Requirement:</u>	
B. Requirements	
* * *	
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	
R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.	
R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.	
* * *	
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. * * * Compliance may be demonstrated by either	

of the following two methods:

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

D. Compliance

1.4 Additional Compliance Information

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Clarification needed:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

- (1) although a Disturbance¹ that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
- (2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve

¹ Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

- (3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for “enough Contingency Reserve to cover the most severe single Contingency”) meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute “Reportable Disturbances.” See Section 1.4 of Part D of BAL-002-0 (where the “Additional Compliance Information” includes a definition of “Reportable Disturbance”).

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (see, e.g., Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that “An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.”)

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Standards Announcement

Project 2009-19 Interpretation of BAL-002-0 NWPP Reserve Sharing Group

Recirculation Ballot Window Now Open: September 28 – October 8, 2012

[Now Available](#)

A recirculation ballot for the Interpretation of BAL-002-0 - Disturbance Control Performance Requirements R4 and R5 for NWPP Reserve Sharing Group is open through **8 p.m. Eastern on Monday, October 8, 2012.**

Instructions

Members of the ballot pool associated with this project may log in and submit their vote for the interpretation by clicking [here](#).

Next Steps

The Interpretation of BAL-002-0 will be presented to the Board of Trustees for adoption in November 2012 and then filed with the appropriate regulatory authorities.

Background

Northwest Power Pool Reserve Sharing Group (NWPP) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are:

1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; and

2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when:

(a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group, and

(b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Additional information is available on the [project page](#).

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2009-19 – Interpretation of BAL-002-0 - NWPP Reserve Sharing Group

Recirculation Ballot Results

[Now Available](#)

A recirculation ballot for the Interpretation of BAL-002-0 - Disturbance Control Performance Requirements R4 and R5 for NWPP Reserve Sharing Group concluded on Monday, October 8, 2012.

Voting statistics are listed below, and the [Ballot Results](#) page provides a link to the detailed results.

Ballot Results
Quorum: 85.11%
Approval: 90.34%

Next Steps

The interpretation will be presented to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

Northwest Power Pool Reserve Sharing Group (NWPP) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are; 1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; 2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and 3) the meaning of the phrase “excluded

from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Additional information is available on the [project page](#).

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Newsroom

Site Map

Contact NERC

SEARCH NERC.com

Advanced Search

GO

- Standards Admin Home
- Registered Ballot Body
- Ballot Events
- Current Ballot Pools
- Current Ballots
- Previous Ballots
- Vetting
- Proxy Pool
- NERC Home

Ballot Results	
Ballot Name:	Project 2009-19 BAL-002 Recirculation Ballot
Ballot Period:	9/28/2012 - 10/8/2012
Ballot Type:	Initial
Total # Votes:	303
Total Ballot Pool:	356
Quorum:	85.11 % The Quorum has been reached
Weighted Segment Vote:	90.34 %
Ballot Results:	The Standard has Passed

Summary of Ballot Results								
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	94	1	62	0.849	11	0.151	8	13
2 - Segment 2.	10	1	9	0.9	1	0.1	0	0
3 - Segment 3.	81	1	55	0.887	7	0.113	7	12
4 - Segment 4.	25	1	16	0.941	1	0.059	3	5
5 - Segment 5.	75	1	49	0.961	2	0.039	9	15
6 - Segment 6.	52	1	36	0.947	2	0.053	9	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	10	0.6	6	0.6	0	0	1	3
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.6	4	0.4	2	0.2	1	0
Totals	356	7.4	239	6.685	26	0.715	38	53

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	

1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Matthey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Brett A. Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	

1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Abstain	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Ken A Gardner	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	El Paso Electric Company	Tracy Van Slyke	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		

3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Pepco Holdings, Inc.	Mark R Jones	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Steve Wickel	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Turlock Irrigation District	James Ramos	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney		
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative
4	Tacoma Public Utilities	Keith Morissette	Affirmative
4	Turlock Irrigation District	Steven C Hill	Affirmative
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative
5	AEP Service Corp.	Brock Ondayko	Negative
5	Amerenue	Sam Dwyer	Affirmative
5	Arizona Public Service Co.	Edward Cambridge	Affirmative
5	Avista Corp.	Edward F. Groce	Affirmative
5	BC Hydro and Power Authority	Clement Ma	Affirmative
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	
5	Calpine Corporation	Phillip Porter	Affirmative
5	City and County of San Francisco	Daniel Mason	Abstain
5	City of Austin dba Austin Energy	Jeanie Doty	
5	City of Redding	Paul A. Cummings	Affirmative
5	City of Tallahassee	Karen Webb	Affirmative
5	Cleco Power	Stephanie Huffman	Affirmative
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative
5	Consumers Energy Company	David C Greyerbiehl	Affirmative
5	Dairyland Power Coop.	Tommy Drea	Affirmative
5	Deseret Power	Philip B Tice Jr	Affirmative
5	Detroit Edison Company	Christy Wicke	Affirmative
5	Detroit Renewable Power	Marcus Ellis	
5	Duke Energy	Dale Q Goodwine	Negative
5	El Paso Electric Company	David Hawkins	Affirmative
5	Essential Power, LLC	Patrick Brown	Affirmative
5	Exelon Nuclear	Michael Korchynsky	Affirmative
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative
5	Florida Municipal Power Agency	David Schumann	
5	Great River Energy	Preston L Walsh	Affirmative
5	Hydro-Québec Production	Roger Dufresne	
5	Imperial Irrigation District	Marcela Y Caballero	Abstain
5	JEA	John J Babik	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative
5	Kissimmee Utility Authority	Mike Blough	
5	Lakeland Electric	James M Howard	
5	Lincoln Electric System	Dennis Florom	Affirmative
5	Los Angeles Department of Water & Power	Kenneth Silver	
5	Manitoba Hydro	S N Fernando	Affirmative
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain
5	MEAG Power	Steven Grego	
5	Muscatine Power & Water	Mike Avesing	Affirmative
5	Nebraska Public Power District	Don Schmit	Affirmative
5	New York Power Authority	Wayne Sipperly	Affirmative
5	NextEra Energy	Allen D Schriver	Affirmative
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative
5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative
5	PacifiCorp	Sandra L. Shaffer	Affirmative
5	Platte River Power Authority	Roland Thiel	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain
5	PPL Generation LLC	Annette M Bannon	Abstain
5	Proven Compliance Solutions	Mitchell E Needham	Abstain
5	Public Utility District No. 1 of Chelan County	John Yale	Affirmative
5	Public Utility District No. 1 of Lewis County	Steven Grega	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative
5	Salt River Project	William Alkema	Affirmative
5	Santee Cooper	Lewis P Pierce	Affirmative
5	Seattle City Light	Michael J. Haynes	Affirmative
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative

5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	Turlock Irrigation District	Marty Rojas	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirschak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Tony Soto	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	Progress Energy	John T Sturgeon	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Turlock Irrigation District	Amy Petersen	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	



6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		James A Maenner		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8	Ascendant Energy Services, LLC	Raymond Tran	Affirmative	
8	Energy Mark, Inc.	Howard F. Illian	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Abstain	
8	Volkman Consulting, Inc.	Terry Volkman		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	
10	Southwest Power Pool RE	Emily Pennel	Abstain	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

 [Account Log-In/Register](#)

.....

Copyright © 2009 by the North American Electric Reliability Corporation. : All rights reserved.
A New Jersey Nonprofit Corporation

Exhibit D

Interpretation Drafting Team Roster for NERC Standards Development
Project 2009-1

**Project 2009-19 Interpretation of BAL-002-0 for NWPP
Drafting Team Roster**

Name and Title Affiliation Contact Info	Bio
Albert DiCaprio - Chair PJM 955 Jefferson Avenue Valley Forge Corporate Center Norristown, PA 19403-2497 dicapram@pjm.com	Albert DiCaprio has been employed by PJM since 1970. His experience at PJM includes System Operations Department in which he helped developed PJM generation control program, PJM's Accounting for regulation program and PJM's Fuel Supply Emergency procedures; in the System Performance Department he initiated performance monitoring and benchmarking programs, and PJM's Energy by Fuel type tracking system; and he helped launch PJM's first retail customer support program. As Senior Strategist, Mr. DiCaprio provides analysis and support for PJM positions on NERC standards and FERC initiatives. Mr. DiCaprio is a current member of the Standards Committee and has served on various NERC committees most notably as Chairman of the Performance Subcommittee when the first Control Performance Standard was approved and he served on the Task Force whose efforts led to the development of the NERC Functional Model. Mr. DiCaprio serves as the chairman of the ISO/RTO's Standards Review Committee who review and comment on NERC Reliability Standards, NAESB Business Practices and FERC initiatives related to reliability standards. Active in the IEEE, he is a senior member and has published various papers and has served on Technical Activities committees for two Joint IEEE-CIGRE conferences. Internationally, Mr. DiCaprio serves as the chairman of the International Group on Comparison of Transmission Operation Practices. Mr. DiCaprio has been part of CIGRE's initiative into Energy Markets and has been active with Study Committee C5 (Markets and Regulation) since its beginning in 2000 and received CIGRE 2009 Technical Committee Award for his contributions to the Study Committee. He is also active in a Joint Working Group with Markets and Operations, and Working groups on System Design (WG C5-7) and on Integration of Renewable resources and Demand-side Management (WG C5-11). He has a bachelor's in electrical engineering from Drexel University in Philadelphia and a Master's in System Operations from the University of Pennsylvania.
Gerald Beckerle Ameren Sr Transmission Operations Supervisor Transmission Operations T 314.554.6413	Gerald D. Beckerle, Senior Transmission Operations Supervisor, Ameren Services, St. Louis, MO, has a BSEE from the University of Missouri, Columbia. He has been with Ameren for 32 years, 25 of those years in System Operations, which has been or is currently responsible for Transmission, Generation, and daily interchange. Current activities include:

GBeckerle@ameren.com	SERC Operating Committee Chairman NERC Resources Subcommittee Vice-Chairman NERC Operating Committee member and serving on the committee's executive committee NERC Balancing Authority Reliability Based Controls Standard Drafting Team member NERC Frequency Response Standard Drafting Team Contributor Past Activities included: Balancing Authority Controls SAR and SDT member prior to merging into the BARC SDT. Midwest Reserve Sharing Group representative for Ameren RFC Version Zero Standards Drafting Team member MAIN Operating Reserve Subcommittee member
Howard F. Illian President Energy Mark, Inc. 334 Satinwood Ct. N. Buffalo Grove, Illinois 60089 (847) 913-5491 howard.illian@energymark.com	Howard F. Illian graduated from Carnegie Institute of Technology (Carnegie-Mellon University) in 1970 with a B.S. in Electrical Engineering. From 1970 until 1982 he worked for ComEd in the field of Operations Research, and was Supervisor, Economic Research and Load Forecasting from 1976 until he was reassigned to Bulk Power Operations in 1982 where he was Technical Services Director when he retired in 1998. He is now President of Energy Mark, Inc., a consulting firm specializing in the commercial relationships required by restructuring. He has authored numerous papers, and has testified as an expert witness before the Illinois EPA, the Federal EPA, the Illinois Commerce Commission and the Public Utility Commission of Texas. He has developed and applied several new mathematical techniques for use in simulation and decision making. He has served on the NERC Performance Subcommittee, the Interconnected Operations Services Implementation Task Force, the Joint Inadvertent Interchange Task Force, and the NAESB Inadvertent Interchange Payback Task Force. Recent work includes significant contributions to the development of new NERC Control Performance Standards including the Balancing Authority Ace Limit and a suggested mathematical foundation for control based on classical statistics. His current research concentrates on the development of technical definitions for Ancillary or Reliability Services including frequency response and their market implementation.

Guy Quintin Ingénieur Chef – Centre de conduite du réseau Programmation et Contrôle du réseau Direction CMÉ Hydro-Québec TransÉnergie Tel: 514-289-2211 #3150 cell: 514-793-9838 Quintin.Guy@hydro.qc.ca	Mr. Quintin studied at the University of Montreal and graduated in Electrical Engineering (B.S. Eng.) in 1981. Since then, he has worked at Hydro-Québec: two years in the Distribution department, seven years at the Regional Operations in the Eastern Quebec and 20 years as an Operation Engineer at the System Control Center in Montreal. He has been a member of the NPCC Control Performance Working Group (CO-1) for five years. Since 2010, he has been a manager of the operators in the Control Room. He is a member of the NPCC System Operations Managers Working Group and the NERC Balancing Authority Reliability-based Control Standard Drafting Team.
Darrel Richardson Standards Developer North American Electric Reliability Corporation 3353 Peachtree Road NE, Suite 600 – North Tower Atlanta, GA 30326 609-613-1848 cell darrel.richardson@nerc.net	Darrel Richardson joined the NERC staff as a Standards Developer. In this role he facilitates and provides guidance to drafting teams in the development of technically excellent and timely reliability standards for the reliable operation and planning of the bulk power system. Darrel began his career with NERC in November 2007. Darrel has extensive experience in the utility industry having spent over 37 years with Illinois Power Company. In his tenure at Illinois Power he held several different positions in the Engineering, Planning and Operations groups. Among the position he has held are Transmission Coordinator, Generation Coordinator, Manager Wholesale Marketing, Manager Wholesale Marketing and Trading, Director Generation Control and Manager Compliance.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Newsroom

Site Map

Contact NERC

SEARCH NERC.com

Advanced Search

GO

User Name

Password

Log in

Register

- Ballot Pools
- Current Ballots
- Ballot Results
- Registered Ballot Body
- Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2010-11 Recirculation Ballot Jan 2013_in
Ballot Period:	1/22/2013 - 1/31/2013
Ballot Type:	Recirculation
Total # Votes:	317
Total Ballot Pool:	358
Quorum:	88.55 % The Quorum has been reached
Weighted Segment Vote:	69.63 %
Ballot Results:	The Standard has Passed

Summary of Ballot Results								
Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	102	1	57	0.814	13	0.186	21	11
2 - Segment 2.	10	0.9	6	0.6	3	0.3	0	1
3 - Segment 3.	82	1	42	0.724	16	0.276	15	9
4 - Segment 4.	25	1	11	0.786	3	0.214	8	3
5 - Segment 5.	73	1	30	0.732	11	0.268	20	12
6 - Segment 6.	48	1	23	0.657	12	0.343	11	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	2	0.2	3	0.3	0	3
9 - Segment 9.	3	0.2	0	0	2	0.2	1	0
10 - Segment 10.	7	0.6	5	0.5	1	0.1	1	0
Totals	358	7.2	176	5.013	64	2.187	77	41

Individual Ballot Pool Results				
Segment	Organization	Member	Ballot	Comments
1		Vijay Sankar		
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Abstain	

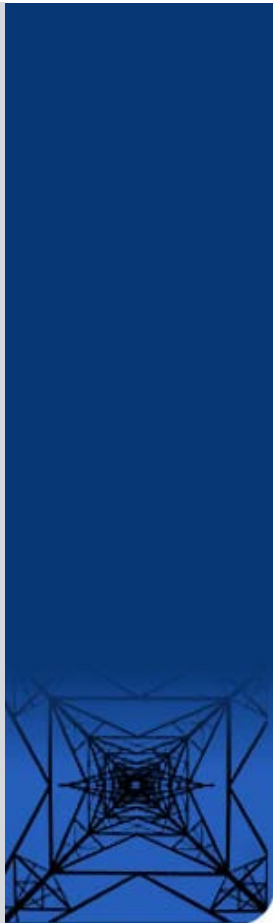
1	Balancing Authority of Northern California	Kevin Smith	Abstain
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative
1	Beaches Energy Services	Joseph S Stonecipher	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative
1	City of Tallahassee	Daniel S Langston	Affirmative
1	Clark Public Utilities	Jack Stamper	Abstain
1	Colorado Springs Utilities	Paul Morland	Affirmative
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative
1	Corporate Risk Solutions, Inc.	Joseph Doetzel	Abstain
1	CPS Energy	Richard Castrejano	Affirmative
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative
1	Deseret Power	James Tucker	Abstain
1	Dominion Virginia Power	Michael S Crowley	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative
1	Entergy Transmission	Oliver A Burke	Negative
1	FirstEnergy Corp.	William J Smith	Affirmative
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative
1	Florida Power & Light Co.	Mike O'Neil	Affirmative
1	FortisBC	Curtis Klashinsky	
1	Gainesville Regional Utilities	Richard Bachmeier	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative
1	Great River Energy	Gordon Pietsch	Affirmative
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative
1	Idaho Power Company	Molly Devine	Affirmative
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative
1	JEA	Ted Hobson	
1	KAMO Electric Cooperative	Walter Kenyon	
1	Keys Energy Services	Stanley T Rza	Affirmative
1	Lakeland Electric	Larry E Watt	Affirmative
1	Lee County Electric Cooperative	John W Delucca	Affirmative
1	Lincoln Electric System	Doug Bantam	
1	Long Island Power Authority	Robert Ganley	Affirmative
1	Lower Colorado River Authority	Martyn Turner	Abstain
1	M & A Electric Power Cooperative	William Price	Affirmative
1	Manitoba Hydro	Nazra S Gladu	Affirmative
1	MEAG Power	Danny Dees	Abstain
1	MidAmerican Energy Co.	Terry Harbour	Abstain
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative
1	National Grid USA	Michael Jones	Affirmative
1	Nebraska Public Power District	Cole C Brodine	Affirmative
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative
1	New York Power Authority	Bruce Metruck	Abstain
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative
1	Northeast Utilities	David Boguslawski	Negative
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative
1	NorthWestern Energy	John Canavan	Affirmative
1	Ohio Valley Electric Corp.	Robert Matthey	Affirmative
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain
1	Omaha Public Power District	Doug Peterchuck	Affirmative
1	Oncor Electric Delivery	Jen Fiegel	Affirmative
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Negative
1	PacifiCorp	Ryan Millard	Abstain
1	Platte River Power Authority	John C. Collins	Negative
1	Portland General Electric Co.	John T Walker	Affirmative
1	Potomac Electric Power Co.	David Thorne	Affirmative

1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Duncel	Abstain	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Mississippi Electric Power Association	Rodney A. Wilson		
1	Southern California Edison Company	Steven Mavis	Abstain	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris	Negative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Homestead	Orestes J Garcia	Affirmative	
3	City of Redding	Bill Hughes	Abstain	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	
3	Consumers Energy	Richard Blumenstock	Abstain	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr		

3	Entergy	Joel T Plessinger	Negative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Abstain	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Abstain	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Negative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	American Municipal Power	Kevin Koloini		
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Abstain	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	

4	Consumers Energy	David Frank Ronk	Abstain	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Integrus Energy Group, Inc.	Christopher Plante	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morissette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Abstain	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	
5	Consumers Energy Company	David C Greyerbiehl	Abstain	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Electric Power Supply Association	John R Cashin		
5	Energy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Neil D Hammer	Abstain	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		

5	Platte River Power Authority	Roland Thiel	Negative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Company	Denise Yaffe	Negative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Negative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Abstain	
6	Cleco Power LLC	Robert Hirschak		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Negative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Abstain	
6	South Mississippi Electric Power Association	Joel Rogers		
6	Southern California Edison Company	Lujuanna Medina	Negative	



6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	
8		Edward C Stein		
8		Roger C Zaklukiewicz		
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Negative	
8	Transmission Strategies, LLC	Bernie M Pasternack	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkman Consulting, Inc.	Terry Volkman	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Abstain	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Negative	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council	Guy V. Zito	Abstain	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy

404.446.2560 voice : 404.446.2595 fax

Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326

Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

 Account Log-In/Register

.....

Copyright © 2012 by the North American Electric Reliability Corporation. : All rights reserved.
A New Jersey Nonprofit Corporation

Standard Authorization Request Form

Title of Proposed Standard: (Project 2008-02)	
PRC-010-0 — Assessment of the Design and Effectiveness of UVLS Program	
PRC-022-1 — Under-Voltage Load Shedding Program Performance	
Request Date	January 11, 2010
SC Approval Date	January 151, 2010

SAR Requester Information	SAR Type <i>(Check a box for each one that applies.)</i>
Name: TBD	☐ New Standard
Primary Contact Stephen Crutchfield NERC Staff	☒ Revision to existing Standard 1. PRC-010-0 — Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program PRC-022-1 — Undervoltage Load Shedding Program Performance TPL-001 through TPL-004 as appropriate.
Telephone 609-651-9455 Fax	☐ Withdrawal of existing Standard
E-mail Stephen.crutchfield@nerc.net	☐ Urgent Action

Purpose

To improve the existing standards on Under Voltage Load Shedding (UVLS) to include criteria for Under Voltage Load Shedding programs such that the programs work as intended to shed load when needed and prevent voltage collapse and voltage instability in the Bulk Electric System.

Industry Need

Load characteristics have changed drastically over the last few years and FIDVR events have become increasingly more probable with the increased penetration of low-inertia air conditioner loads that lack compressor undervoltage protection. Protection and controls impacts on FIDVR events abound. Requirements are needed for FIDVR studies that include protection and controls actions and potential misoperations.

Two 2003 Blackout recommendations¹ 8b and 13c relating to UVLS need to be considered in the standard development process.

¹ From the report, "August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts February 10, 2004"

Recommendation 8b: Each regional reliability council shall complete an evaluation of the feasibility and benefits of installing under-voltage load shedding capability in load centers within the region that could become unstable as a result of being deficient in reactive power following credible multiple-contingency events. The regions are to complete the initial studies and report the results to NERC within one year. The regions are requested to promote the installation of under-voltage load shedding capabilities within critical areas, as determined by the studies to be effective in preventing an uncontrolled cascade of the power system.

Recommendation 13c: The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods and practices used for system design, planning and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information.

Technical studies addressing FIDVR and the two blackout recommendations, as well as an evaluation of the existing standards have been prepared by various NERC technical committees and identify areas where the existing standards need improvement to prevent voltage collapse and voltage instability through UVLS programs.

Brief Description

There are two standards to be revised under this SAR:

- PRC-010-0 — “Assessment of the Design and Effectiveness of UVLS Program” specifies requirements for the responsible entity to periodically conduct and document an assessment of the effectiveness of the UVLS program.
- PRC-022-1 — “Under-Voltage Load Shedding Program Performance” specifies requirements for responsible entities to analyze and document operation and misoperation of UVLS systems.

These standards should be consolidated, and specific criteria for UVLS programs and assessments of those UVLS programs should be added; “fill-in-the-blank” elements should be eliminated; the issues identified by stakeholders and FERC in Attachment 1 should be addressed; and the concepts in the following papers should be addressed:

“Fault-Induced Delayed Voltage Recovery”

“Guidelines for Developing an Under Voltage Load Shedding (UVLS) Evaluation Program”

“Evaluation of Criteria, Methods, and Practices used for System Design, Planning, and Analysis in Response to NERC Blackout Recommendation 13c”

“NERC SPCTF Technical Review of PRC-010-0 — Assessment of the Design and Effectiveness of UVLS Program”

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

The standard drafting team will also modify the standards to conform to the latest version of NERC’s Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure as described in the “Global Improvements” section of Volume I of the Reliability Standards Development Plan and included in this SAR as Attachment 2.

Detailed Description

PRC-010-0 —Assessment of the Design and Effectiveness of UVLS Program and PRC-022-1 —Under-Voltage Load Shedding Program Performance should be consolidated, and specific criteria for UVLS programs and assessments of those UVLS programs should be added; “fill-in-the-blank” elements should be eliminated; the issues identified by stakeholders and FERC in Attachment 1 should be addressed; and the concepts in the following papers should be addressed:

“Fault-Induced Delayed Voltage Recovery” was developed jointly by the Transmission Issues Subcommittee and the System Protection and Control Subcommittee. The report identifies a Fault Induced Delayed Voltage Recovery (FIDVR) as the phenomenon whereby system voltage remains at significantly reduced levels for several seconds after a transmission, sub transmission, or distribution fault has been cleared. Significant load loss due to motor protective device action can result, as can significant loss of generation, with a potential secondary effect of high system voltage due to load loss. A severe event can result in fast voltage collapse.

“Guidelines for Developing an Under Voltage Load Shedding (UVLS) Evaluation Program” was prepared by the Transmission Issues Subcommittee related to NERC blackout recommendation 8b (dated September 13, 2006).

Recommendation 8b: Each regional reliability council shall complete an evaluation of the feasibility and benefits of installing under-voltage load shedding capability in load centers within the region that could become unstable as a result of being deficient in reactive power following credible multiple-contingency events. The regions are to complete the initial studies and report the results to NERC within one year. The regions are requested to promote the installation of under-voltage load shedding capabilities within critical areas, as determined by the studies to be effective in preventing an uncontrolled cascade of the power system.

“Evaluation of Criteria, Methods, and Practices used for System Design, Planning, and Analysis in Response to NERC Blackout Recommendation 13c” was prepared by the Transmission Issues Subcommittee of the NERC Planning Committee to address recommendation 13c (Draft Dated February 22, 2006). Section III.2 - Use of Undervoltage Load Shed (UVLS) Schemes identifies the need for greater consistency in the criteria for applying UVLS.

Recommendation 13c: The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods and practices used for system design, planning and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information.

“NERC SPCTF Technical Review of PRC-010-0 — Assessment of the Design and Effectiveness of UVLS Program” was prepared by the System Protection and Controls Task Force of the NERC Planning Committee (dated May 17, 2007) identifies the need to expand the scope of the standards’ applicability to include generator owners and improved coordination with generator station under voltage protection as well as improved coordination with other protection systems.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Standards Authorization Request Form

Reliability Functions

The Standard will Apply to the Following Functions <i>(Check box for each one that applies.)</i>		
☒	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.
☐	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.

Standards Authorization Request Form

Reliability and Market Interface Principles

Applicable Reliability Principles <i>(Check box for all that apply.)</i>	
☒	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? <i>(Select 'yes' or 'no' from the drop-down box.)</i>	
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	

Standards Authorization Request Form

Related Standards

Standard No.	Explanation
TPL-001-1	See SPCTF Report

Related SARs

SAR ID	Explanation
Project 2008-01	The two projects will require “monitoring” to see if coordination is required.
Project 2007-06	The two projects will require “monitoring” to see if coordination is required between the revised standards and PRC-001

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1 — FERC Order 693 Directives and Stakeholder Issues

Source	Language
Other	Modify standard to conform to the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure
PRC-010-0 — Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	
FERC Order 693	Require that an integrated and coordinated approach be included in all protection systems on the bulk power system, including generators and transmission lines, generators' low-voltage ride-through capabilities, and UFLS and UVLS systems. Paragraph 1509. We appreciate MEAG's feedback to our response in the NOPR. For the reasons discussed in the NOPR, as well as our explanation above, the Commission approves Reliability Standard PRC-010-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC-010-0 through the Reliability Standards development process that requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities, and UFLS and UVLS programs.
FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000	In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: • FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) • NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), • FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and • NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.
Fill in the Blank Team	Placeholder
Phase III/IV Team	• PRC-010 is a very weak standard — it only requires documentation and, in very broad terms, 'coordination' — it doesn't specify any level of desired performance or any specific scope for coordination. There should be some details to identify what the coordination must achieve — such as verification that the UVLS will trip when voltage drops to a specified voltage and verification that only a specified amount of load will be tripped and that other special protection systems will not be activated by the UVLS program. • There is no requirement that identifies the desired performance of a UVLS program (what voltage set points and timing are acceptable?). • What is the reliability-related need for the RRO to collect data on misoperations and operations of UVLS programs? Is this information used for anything?
Team Comments	Provide clarity where the Planning Authority is mentioned

Standards Authorization Request Form

Source	Language
Version 0 Team	- Define evidence - Exemptions for some who use shunt reactors - Level 4 vs. level 1 changes
PRC-022-1 — Under-Voltage Load Shedding Program Performance	
FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000	In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: - FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) - NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), - FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and - NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.
FERC Order 693	Consider FirstEnergy's suggestions to revise requirement R1.3 as part of the standards development process. Paragraph 1564. FirstEnergy comments that Requirement R1.3 requires "a simulation of the event, if deemed appropriate by the RRO" and believes that the applicable entities such as transmission operators may not be able to simulate large system events. FirstEnergy suggests that Requirement R1.3 be revised to state that "a simulation of the event, if deemed appropriate, and assisted by the [regional reliability organization]."
Phase III/IV Team	- Consider incorporating into this family of standards a requirement that each TO should study, and implement if found effective, a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES. - The reliability-related need for the RRO to collect data on operations and misoperations isn't clear — should this be revised and made available instead to the Compliance Monitor or to the Planning Authority? - The TO should also be required to demonstrate that its UVLS program is coordinated with adjacent TOs.

Issues to be Considered by Drafting Team Project 2008-02 — Undervoltage Load Shedding	
Standard #	Title
PRC-022-1	Under-Voltage Load Shedding Program Performance
Issues	FERC Order 693 Disposition: Approved. Consider FirstEnergy's suggestions to revise requirement R1.3 as part of the standards development process. {Paragraph 1564. FirstEnergy comments that Requirement R1.3 requires "a simulation of the event, if deemed appropriate by the RRO" and believes that the applicable entities such as transmission operators may not be able to simulate large system events. FirstEnergy suggests that Requirement R1.3 be revised to state that "a simulation of the event, if deemed appropriate, and assisted by the [regional reliability organization]."} } Phase III / IV comments • Consider incorporating into this family of standards a requirement that each TO should study, and implement if found effective, a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES. • The TO should also be required to demonstrate that its UVLS program is coordinated with adjacent TOs. • The reliability-related need for the RRO to collect data on operations and misoperations isn't clear – should this be revised and made available instead to the Compliance Monitor or to the Planning Authority? Other • Modify standard to conform to the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure. FERC's December 20, 2007 and April 4, 2008 Orders in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 • In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none owned physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be applied. Each drafting team responsible for reliability standards applicable to LSEs is to review and change as necessary, requirements in the applicable reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: • FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) • NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), • FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf) and • NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.

Attachment 2 — Global Improvements

Global Improvements

The standard drafting team for each of the projects identified in this plan is expected to review the assigned standards and modify the standards to conform to the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure as described in this "Global Improvements" section.

Statutory Criteria

In accordance with Section 215 of the Federal Power Act, FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that "the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest."

The first three of these criteria can be addressed in large part by the diligent adherence to NERC's *Reliability Standards Development Procedure*, which has been certified by the ANSI as being open, inclusive, balanced, and fair. Users, owners, and operators of the bulk power system that must comply with the standards, as well as the end-users who benefit from a reliable supply of electricity and the public in general, gain some assurance that standards are just, reasonable, and not unduly discriminatory or preferential because the standards are developed through an ANSI-accredited procedure.

The remaining portion of the statutory test is whether the standard is "in the public interest." Implicit in the public-interest test is that a standard is technically sound and ensures a level of reliability that should be reasonably expected by end-users of electricity. Additionally, each standard must be clearly written, so that bulk power system users, owners, and operators are put on notice of the expected behavior. Ultimately, the standards should be defensible in the event of a governmental authority review or court action that may result from enforcing the standard and applying a financial penalty.

The standards must collectively provide a comprehensive and complete set of technically sound requirements that establish an acceptable threshold of performance necessary to ensure the reliability of the bulk power system. "An adequate level of reliability" would argue for both a complete set of standards addressing all aspects of bulk power system design, planning, and operation that materially affect reliability, and for the technical efficacy of each standard. The Commission directed NERC to define the term, "adequate level of reliability" as part of its January 18, 2007 Order on Compliance Filing. Accordingly, NERC's Operating and Planning Committees prepared the definition and the NERC Board approved it at its February 2008 meeting for filing with regulatory authorities. The NERC Standards Committee was then tasked to integrate the definition into the development of future reliability standards.

Quality Objectives

To achieve the goals outlined above, NERC has developed 10 quality objectives for the development of reliability standards. Drafting teams working on assigned projects are charged to ensure their work adheres to the following quality objectives:

1. **Applicability** — Each reliability standard shall clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted. Such functional classes² include: ERO, Regional Entities, reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange authorities, transmission service providers, market operators, planning coordinators, transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers. Each reliability standard that does not apply to the entire North American bulk power system shall also identify the geographic applicability of the standard, such as an interconnection, or within a regional entity area. The applicability section of the standard should also include any limitations on the applicability of the standard based on electric facility characteristics, such as a requirement that applies only to the subset of distribution providers that own or operate underfrequency load shedding systems.
2. **Purpose** — Each reliability standard shall have a clear statement of purpose that shall describe how the standard contributes to the reliability of the bulk power system.
3. **Performance Requirements** — Each reliability standard shall state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest. Each requirement is not a “lowest common denominator” compromise, but instead achieves an objective that is the best approach for bulk power system reliability, taking account of the costs and benefits of implementing the proposal.
4. **Measurability** — Each performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement. Each performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement. If performance results can be practically measured quantitatively, metrics shall be provided within the requirement to indicate satisfactory performance.
5. **Technical Basis in Engineering and Operations** — Each reliability standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.
6. **Completeness** — Each reliability standard shall be complete and self-contained. The standards shall not depend on external information to determine the required level of performance.
7. **Consequences for Noncompliance** — Each reliability standard shall make clearly known to the responsible entities the consequences of violating a standard, in combination with guidelines for penalties and sanctions, as well as other ERO and Regional Entity compliance documents.
8. **Clear Language** — Each reliability standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

² These functional classes of entities are derived from NERC’s Reliability Functional Model. When a standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in Reliability Standards.

- 9. Practicality** — Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.
- 10. Consistent Terminology** — Each reliability standard, to the extent possible, shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards Development Process.

In addition to these factors, standard drafting teams also contemplate the following factors the Commission uses to approve a proposed reliability standard as outlined in Order No. 672. A standard proposed to be approved:

1. Must be designed to achieve a specified reliability goal

“321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of bulk power system facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to cyber security protection.”

“324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO’s process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.”

2. Must contain a technically sound method to achieve the goal

“324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal.

Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO’s process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.”

3. Must be applicable to users, owners, and operators of the bulk power system, and not others

“322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.”

- 4. Must be clear and unambiguous as to what is required and who is required to comply**
“325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.”
- 5. Must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation**
“326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.”
- 6. Must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner**
“327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.”
- 7. Should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect “best practices” without regard to implementation cost**
“328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or “best practice,” for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.”
- 8. Cannot be “lowest common denominator,” i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability**
“329. The proposed Reliability Standard must not simply reflect a compromise in the ERO’s Reliability Standard development process based on the least effective North American practice — the so-called “lowest common denominator”—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.”
- 9. Costs to be considered for smaller entities but not at consequence of less than excellence in operating system reliability**
“330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a “lowest common denominator” Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.”
- 10. Must be designed to apply throughout North American to the maximum extent achievable with a single reliability standard while not favoring one area or approach**

“331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.”

11. No undue negative effect on competition or restriction of the grid

“332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.”

12. Implementation time

“333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.”

13. Whether the reliability standard process was open and fair

“334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO’s Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.”

14. Balance with other vital public interests

“335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.”

15. Any other relevant factors

“323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.”

“337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed reliability standard.”

Issues Related to the Applicability of a Standard

In Order No. 672, the Commission states that a proposed reliability standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the bulk power system must know what they are required to do to maintain reliability. Section 215(b) of the FPA requires all “users, owners and operators of the bulk power system” to comply with Commission-approved reliability standards.

The term “users, owners, and operators of the bulk power system” defines the statutory applicability of the reliability standards. NERC’s Reliability Functional Model (Functional Model) further refines the set of users, owners, and operators by identifying categories of functions that entities perform so the applicability of each standard can be more clearly defined. Applicability is clear if a standard precisely states the applicability using the functions an entity performs. For example, “Each Generator Operator shall verify the reactive power output capability of each of its generating units” states clear applicability compared with a standard that states “a bulk power system user shall verify the reactive power output capability of each generating unit.” The use of the Functional Model in the standards narrows the applicability of the standard to a particular class or classes of bulk power system users, owners, and operators. A standard is more clearly enforceable when it narrows the applicability to a specific class of entities than if the standard simply references a wide range of entities, e.g., all bulk power system users, owners, and operators.

In determining the applicability of each standard and the requirements within a standard, the drafting team should follow the definitions provided in the NERC Glossary of Terms Used in Reliability Standards and should also be guided by the Functional Model.

In addition to applying definitions from the Functional Model, the revised standards must address more specific applicability criteria that identify only those entities and facilities that are material to bulk power system reliability with regard to the particular standard.

The drafting team should review the registration criteria provided in the NERC Statement of Compliance Registry Criteria, which is the criteria for applicability. The registration criteria identify the criteria NERC uses to identify those entities responsible for compliance to the reliability standards. Any deviations from the criteria used in the Statement of Compliance Registry Criteria must be identified in the applicability section of the. It is also important to note that standard drafting teams cannot set the applicability of reliability standards to extend to entities beyond the scope established by the criteria for inclusion on NERC’s Compliance Registry. This is expressly prohibited by Commission Order No. 693-A.

The goal is to place obligations on the entities whose performance will impact the reliability of the bulk power system, but to avoid painting the applicability with such a broad brush that entities are obligated even when meeting a requirement will make no material contribution to bulk power system reliability.

Every entity class described in the Functional Model performs functions that are essential to the reliability of the bulk power system. This point is best highlighted with the example that might be the most difficult to understand, the inclusion of distribution providers. Section 215 of the FPA specifically excludes facilities used in the local distribution of electric energy. Nonetheless, some of the NERC standards apply to a class of entities called Distribution Providers. Distribution Providers are covered because, although they own and operate facilities in the local distribution of electric energy, they also perform functions affecting and essential to the reliability of the bulk power system. With regard to these facilities and functions that are material to the reliability of the bulk power system, a distribution provider is a bulk power system user. For example, requirements for distribution providers in the reliability standards apply to the underfrequency load shedding relays that are maintained and operated within the distribution system to protect the reliability of the bulk power system. There are also requirements for distribution providers to provide demand forecast information for the planning of reliable operations of the bulk power system.

A similar line of thinking can apply to every other entity in the Functional Model, including Load-serving Entities and Purchasing-selling Entities, which are users of the bulk power system to the extent they transact business for the use of transmission service or to transfer power across the bulk power system. NERC has specific requirements for these entities based on how these uses may impact the reliability of the bulk power systems. Other functional entities are more obviously bulk power system owners and operators, such as Reliability Coordinators, Transmission Owners and Operators, Generator Owners and Operators, Planning Coordinators, Transmission Planners, and Resource Planners. It is the extent to which these entities provide for a reliable bulk power system or perform functions that materially affect the reliability of the bulk power system that these entities fall under the jurisdiction of Section 215 of the FPA and the reliability standards. The use of the Functional Model simply groups these entities into logical functional areas to enable the standards to more clearly define the applicability.

Issues Related to Regional Entities and Reliability Organizations

Because of the transition from voluntary reliability standards to mandatory reliability standards, confusion has occurred over the distinction between Regional Entities and Regional Reliability Organizations. The regional councils have traditionally been the owners and members of NERC. They have been referred to as Regional Reliability Organizations in the Functional Model and in the reliability standards. In an era of voluntary standards and guides, it was acceptable that a number of the standards included requirements for Regional Reliability Organizations to develop regional criteria, procedures, and plans, and included requirements for entities within the region to follow those requirements. Section 215 of the FPA introduced a new term, called “Regional Entity.” Regional Entities have specific delegated authorities, under agreements with NERC, to propose and enforce reliability standards within the region, and to perform other functions in support of the electric reliability organization. The former Regional Reliability Organizations have entered into delegation agreements with NERC to become Regional Entities for this purpose.

Standards Announcement

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations) PRC-004-3

Formal Comment Period Open: January 22, 2013 – February 20, 2013

Upcoming:

Successive Ballot and Non-Binding Poll: February 11-20, 2013

[Now Available](#)

A formal comment period for **PRC-004-3 – Protection System Misoperation Identification and Correction** is now open through 8 p.m. Eastern on **Wednesday, February 20, 2013**.

A successive ballot of **PRC-004-3** and non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Monday, February 11, 2013 through 8 p.m. Eastern on Wednesday, February 20, 2013**.

Instructions

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking [here](#).

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. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background

PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

Project 2010-05.1 is an important part of the ERO's strategic goal to develop technically sufficient standards with requirements that provide clear and unambiguous performance expectations and reliability benefits.

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Unofficial Comment Form

Project 2010-05.1 Protection System Misoperations

Please **DO NOT** use this form for submitting comments. Please use the [electronic form](#) to submit comments on the PRC-004-3 Standard. The comment form must be completed by **February 20, 2013**.

If you have questions please contact Al McMeekin at al.mcmeekin@nerc.net or by telephone at 803-530-1963.

http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

Background Information

This posting is soliciting formal comment.

The second draft of PRC-004-3 was posted for a 45-day formal comment period with concurrent initial ballot from July 25 – September 7, 2012. Stakeholders from approximately 145 companies representing 9 of the 10 Industry Segments provided feedback. The Protection System Misoperation Standard Drafting Team (PSM SDT) has responded to all commenters and developed a third draft of the standard for Protection System Misoperation Identification and Correction based on stakeholder input. Changes to the standard include:

- Revisions to the definition of Protection System Misoperation.
- Revisions to the Applicability 'Facilities' section.
- Revisions to the Requirements and Measures.
- Modifications to the VSLs to reflect the changes in the requirements.
- Revisions to the Implementation Plan including extending the Effective Date from six months to twelve months following applicable regulatory approvals.
- Removal of the Misoperations reporting aspects from the standard.
- Modifications to the Guidelines and Technical Basis section to include more explanation and examples.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Based on stakeholder input, the drafting team revised the definition of a Misoperation. The categories as well as the introductory sentence of the definition were modified for clarity. The introductory sentence indicates that a Misoperation pertains to 'the failure of an Element's composite Protection System to operate as intended.' Do you agree with the revised definition? If not, please provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

2. Requirement R1 was revised to to provide more clarity regarding the responsibilities of the BES interrupting device owner and the Protection System owner (if they are different entities) when a Protection System operation occurs. Do you agree with these changes? If not, please provide specific suggestions for improvement.

☒ Yes

☐ No

Comments: The Protection System component owner who does not also own the interrupting device may be placed in a non-compliant situation through no fault of their own. Their compliance is contingent upon a notification from the owner of the BES interrupting device. If the notification is not made in a timely fashion to allow for investigation, or is not made at all, the Protection System component owner would be non-complaint for not conducting an investigation and documenting the findings within 120 days.

For this situation the BES interrupting device owner should have an abbreviated time frame to notify the Protection System component owner to provide sufficient time to collect the appropriate information and investigate the operation. Conversely, the owner of the Protection System component could be granted more time to investigate (i.e. 120 days from the notification by the BED interrupting device owner).

3. The Measures and VSLs were revised to reflect changes to the requirements. Do you agree with these changes? If not, please provide specific reasons why not and alternative recommendations and justifications.

☐ Yes

☐ No

Comments:

4. The drafting team modified the Guidelines and Technical Basis section to provide more supporting discussions, explanations, and examples for the various aspects of the standard. Do you have any specific suggestions for further improvements?

☐ Yes

☐ No

Comments:

5. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:

Comments: . The Compliance Section of Standard has "The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the BES interrupting device operation occurred prior to the current audit period." The word "open" should precede not only investigation, but action plan and CAP for clarity. It should be made to read "open investigation, open action plan, or open CAP even if the BES interrupting device operation occurred prior to the current audit period".

What is an Entity's compliance obligation for an open investigation or open action plan that occurred prior to regulatory approval of this Standard but in the current audit period of an entity? The new standard establishes specific time limits. If an entity has an operation to investigate the day prior to the compliance obligation date, does the 120 day time limit apply the day the Standard is obligatory?

Regarding the Implementation Plan for Requirements R1, R2, R3 and R4:

"Entities shall be 100% compliant for any new Protection System Operation on the first day of the first calendar quarter twelve months" (this is the compliance obligation date) "following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twelve months following Board of Trustees adoption. Protection System operations that occur before the compliance date shall comply with the previous version of the Standard."

In this section of the Implementation Plan, what is meant by "new"? Is "new" any operation that occur after the compliance obligation date, or during the window of implementation between regulatory approval and compliance obligation date?

A. Introduction

1. **Title:** **Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems**
2. **Number:** PRC-003-1
3. **Purpose:** To ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
 - 4.1. Regional Reliability Organization
5. **Effective Date:** May 1, 2006.

B. Requirements

- R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:
 - R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).
 - R1.2. Data reporting requirements (periodicity and format) for Misoperations.
 - R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.
 - R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.
- R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.
- R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.

C. Measures

- M1. The Regional Reliability Organization shall have procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in R1.
- M2. The Regional Reliability Organization shall have evidence it maintained and periodically updated its procedures for review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in Requirement 2.
- M3. The Regional Reliability Organization shall have evidence it provided its procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in Requirement 3.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain documentation of its procedures for analysis of transmission and generation Protection System Misoperations and any changes to those procedures for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Procedures were not reviewed and updated within the review cycle period as required in R2.

2.2. Level 2: Procedures did not include one of the elements defined in R1.1 through R1.4.

2.3. Level 3: Procedures did not include two or more of the elements defined in R1.1 through R1.4.

2.4. Level 4: There shall be a level four non-compliance if either of the following conditions exist:

2.4.1 No evidence of Procedures.

2.4.2 Procedures were not provided to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06

A. Introduction

- 1. Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
- 2. Number:** PRC-004-1a
- 3. Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
- 4. Applicability**
 - 4.1.** Transmission Owner.
 - 4.2.** Distribution Provider that owns a transmission Protection System.
 - 4.3.** Generator Owner.
- 5. Effective Date:** To be determined

B. Requirements

- R1.** The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.
- R2.** The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
- R3.** The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

C. Measures

- M1.** The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.
- M2.** The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
- M3.** Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

D. Compliance

- 1. Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:

- 2.1. Level 1:** Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.
- 2.2. Level 2:** Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.
- 2.3. Level 3:** Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.
- 2.4. Level 4:** Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

3. Levels of Non-Compliance for Generator Owners

- 3.1. Level 1:** Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.
- 3.2. Level 2:** Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.
- 3.3. Level 3:** Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.
- 3.4. Level 4:** Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
1	February 7, 2006	Adopted by the Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC’s Order is effective as of September 26, 2011)	

Appendix 1

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization’s procedures developed for Reliability Standard PRC-003 Requirement 1. R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term “transmission Protection System.” The NERC Glossary of Terms Used in Reliability Standards contains a definition of “Protection System” but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

Standard PRC-004-2 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
 - 4.1. Transmission Owner.
 - 4.2. Distribution Provider that owns a transmission Protection System.
 - 4.3. Generator Owner.
5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Enforcement Authority**

Regional Entity.

Standard PRC-004-2 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.

Standard Development Timeline

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

Development Steps Completed

- ~~1. The SAR posted for informal comment June 10, 2011 through July 11, 2011.~~
- ~~2.1.~~ SC authorized moving the SAR forward to standard development at the June 9, 2011 meeting.
- ~~2. First posting of Draft Version 1 on The SAR posted for informal comment June 10 – July 11, 2011 with.~~
3. Draft 1 of PRC-004-3 was posted for a 30-day comment period ~~closed on~~ from June 10 – July 11, 2011.
4. Draft 2 of PRC-004-3 was posted for a 45-day concurrent comment and initial ballot period from July 25 – September 7, 2012.

Description of Current Draft

~~This is~~ Draft 3 of PRC-004-3 posted for a ~~45-30-~~day formal comment period with parallel ~~initial~~ successive ballot.

Anticipated Actions	Anticipated Date
~~45~~ 30-day Formal Comment Period with ~~Parallel Initial~~ <u>Successive</u> Ballot	~~July, 2012~~ <u>January, 2013</u>
Recirculation ballot	~~October, 2012~~ <u>February, 2013</u>
BOT Approval	~~November, 2012~~ <u>May, 2013</u>

PRC-004-3 — Protection System Misoperation Identification and Correction

Effective Dates: First day of the first calendar quarter that is ~~six~~twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is ~~six~~twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Misoperation:

~~Failure of a~~ The failure of an Element's composite Protection System to operate as intended.

Any of the following is considered a Misoperation:

1. **Failure to Trip - During Fault** - A failure of a Protection System to operate for a Fault within the zone it is designed to protect. ~~(The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for anthe Element it is designed to protect is correct.)~~.
2. **Failure to Trip - Other Than Fault** - A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. ~~(The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for anthe Element it is designed to protect is correct.)~~.
3. **Slow Trip - During Fault** - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. ~~(Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance is requiredhas not been identified to meet the dynamic stability performance requirements of the TPL standards or bynor is it required to ensure coordination requirements with other Protection Systems.)~~.
4. **Slow Trip - Other Than Fault** - A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.
5. **Unnecessary Trip - During Fault** - A Protection System operation for a Fault for which the Protection System is not intended to operate, ~~excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.~~.

6. **Unnecessary Trip - Other Than Fault** - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Protection System Misoperation Identification and Correction
2. **Number:** PRC-004-3
3. **Purpose:** Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.
4. **Applicability:**

4.1. Functional Entities:

- 4.1.1 Transmission Owner
- 4.1.2 Generator Owner
- 4.1.3 Distribution Provider

~~**Applicability:** SPS and RMS schemes are not included in this version of the standard because they will be handled in the second phase of this project. UVLS is covered by PRC-022. Some functions of relays are not used as protection but as control function or for automation, therefore, any operation of the control function portion of the automation portion of relays are excluded from this standard.~~

Applicability: Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are not included in this version of the standard because they will be handled in the second phase of this project. UVLS is covered by PRC-022-1. Some functions of relays are not used as protection but as control function or for automation, therefore, any operation of the control function portion or the automation portion of relays are excluded from this standard. See the Guidelines and Technical Basis section of the standard for detailed examples of non-protective functions.

4.2. Facilities

4.2.1 Protection Systems for ~~Facilities that are part of the BES~~ BES Elements

~~4.2.2 Facilities not included~~

4.2.2 Underfrequency Load Shedding (UFLS) that trips a BES Element

~~4.2.2.1 Special Protection Systems (SPS) or~~ Remedial Action Schemes (RAS)

~~4.2.2.2~~), and Undervoltage Load Shedding (UVLS)

4.2.3 Relay functions not included ~~(these are nonexcluded~~

~~4.2.3.1~~ 4.2.4 Non-protective functions that may be imbedded within a Protection System) are excluded

~~4.2.3.1 Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples)~~

~~4.2.3.2 Automation (e.g. data collection)~~

5. Background:

A key element for BES reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. PRC-004-3 Protection System ~~Misoperations~~ Misoperation Identification and Correction is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In ~~the NOPR~~ FERC Order No. 693, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The ~~NOPR~~ Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support

the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity

In general, this definition needs more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

The SAR for this project also includes clarifying reporting requirements. Misoperation data, as currently collected and reported, is not usable to establish a consistent metrics for measuring Protection System performance. ~~The SAR includes establishing a~~ As such, the drafting team is removing the data obligation from the standard ~~with uniform applicability, revising the definition and is developing a data request under Section 1600 of Misoperation, and clarifying reporting requirements~~ the NERC Rules of Procedure. NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The data submitted as part of the data request will not be used for compliance or enforcement purposes. The removal of the data collection from the standard does not result in a reduction of reliability as Responsible Entities are required to retain evidence of compliance for audit and compliance purposes under the Compliance Section C 1.2 Evidence Retention portion of the standard.

The proposed requirements of the revised Reliability Standard PRC-004-3 meets the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to determine the cause(s).

- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations of or associated with Special Protection Schemes, Remedial Action Schemes, and Under-Voltage Load Shedding are not addressed in this standard due to their inherent complexities. NERC intends to address these areas through future projects.

Note that the WECC Regional Reliability Standard PRC-004-WECC-1 relates to the reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard.

B. Requirements and Measures

R1. ~~Within 120 calendar days of an interrupting device operation in its Facility caused by a Protection System operation, each~~ Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 ~~Identify~~ Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation.

- If the entity ~~suspects~~ owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation.
- ~~1.1~~ If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System

Rationale for R1: This requirement is the first step to ensuring that practices for reviewing and classifying Protection System operations and correcting Misoperations are consistently employed. The ~~SDT~~drafting team believes 120 calendar days takes into account the seasonal nature of Protection System operations; both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. This requirement mandates entities identify and review Protection System operations. Risks to the BES caused by Misoperations are reduced by reviewing all Protection System operations and investigating any Misoperations to find their cause(s). Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. The initial investigation documentation should be provided to the owner of the Protection System component(s) that contributed to the Misoperation, upon request. The owner of the interrupting device and the entity that owned the component that contributed to the Misoperation should be communicating about the operation before this notification is transmitted. The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3.

component(s) ~~owned by another entity contributed to a Misoperation, notify the owner of that Protection System component~~ and provide any requested investigative information.

1.2 ~~Designate each Misoperation (if any):~~

- ~~o Investigate each~~ The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.

1.3 ~~1.2~~ Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation ~~(if any)~~ shall investigate and document the findings ~~including a cause~~ for each Misoperation including a cause, if identified.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Part 1.1 that may include, but is not limited to, dated lists, logs, or a database (electronic or hard copy format) that documents the date and time of each applicable interrupting device operation and ~~an indication indicates~~ when each related Protection System operation was reviewed. Acceptable evidence for the notification required by Part 1.1 may include, but is not limited to, emails, electronic files, or hard copy records demonstrating transmittal ~~and receipt~~ of information. Acceptable evidence for Part 1.2 may include, but is not limited to, dated lists, logs, or a database (electronic or hard copy format) that documents the date, time, Facility and equipment name associated with each Misoperation. ~~Acceptable evidence for Part 1.3 may include, but is not limited to,~~ a copy of a dated Misoperation investigation report or documented findings, which may include sequence of events, relay targets, summary of DME records for each Misoperation.

Rationale for R2: A formal CAP is a proven tool for resolving operational problems. Based on industry experience and operational coordination timeframes, the SDT believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, or development of a schedule for a CAP. When the cause of a Misoperation is determined from implementing an action plan in accordance with Requirement R4, a CAP must be developed in accordance with Requirement R2.

In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, documenting the reasons for taking no corrective actions is essential for justifying the close of the Misoperation investigation process and for future reference.

R2. ~~Within 60 calendar days of identifying the cause(s) of each Misoperation, the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning]

- ~~Develop and document~~ a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or
- Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R2 that must include a dated CAP or a dated declaration explaining why there is no need to develop a CAP.

Rationale for R2: ~~A formal CAP is a proven tool for resolving operational problems. Based on industry experience and operational coordination timeframes, the SDT believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, development of a schedule, or procurement of funds for a CAP.~~

~~In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, documenting the reasons for taking no corrective actions is essential for justifying the close out the Misoperation investigation process and future reference.~~

R3. ~~For each Misoperation without an identified cause(s), the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning]

- ☉ Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or

- ☉ A declaration explaining why no further actions will be taken.

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R3 that must include a dated action plan or a dated declaration.

R4. ~~For each CAP or action plan, the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall: implement each CAP or action plan, and revise as needed through completion. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning]

~~4.1—Implement the CAP or action plan~~

~~4.2—Maintain detailed implementation records of each CAP or action plan including dated information~~

Rationale for R3: Where a Misoperation cause is not determined during the initial investigation, implementing an action plan of additional investigation/monitoring may determine a cause, and lead to the development of a CAP in accordance with Requirement R2. The 180 calendar ~~days~~day period is the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)

If the investigationaction plan completion does not provide direction for identifying the cause, then pursuing further action is not warranted. In these cases, documenting the reasons is essential for justifying the close ~~out~~of the Misoperation investigation process and for future reference.

Rationale for R4: ~~The CAP or action plan must be fully implemented to accomplish all identified objectives. During the course of implementing a CAP or action plan, revisions may be necessary for a variety of reasons such as scheduling conflicts or resource issues. Documenting the CAP or action plan provides auditable progress and completion confirmation on any plan.~~

Rationale for R4: The CAP or action plan must be completed to accomplish all identified objectives. During the course of implementing a CAP or action plan, revisions may be necessary for a variety of reasons such as scheduling conflicts or resource issues. Documenting the CAP or action plan provides auditable progress and completion confirmation on any plan. When the cause of a Misoperation is determined from implementing an action plan, a CAP must be developed in accordance with Requirement R2.

~~surrounding any revision(s) and completion~~

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that must include, but is not limited to, dated electronic or hard copy records which document the implementation of each CAP and action plan, and the completion of actions ~~and revisions~~ for each CAP or action plan; The evidence may also include dated work management program records, dated work orders, or dated maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority (CEA)

• ~~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. Regional Entity or if the Responsible Entity is owned, operated or controlled by the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity) to be responsible for compliance enforcement.~~

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4 and Measures M1, M2, M3, and M4, since the last audit unless directed by its ~~Compliance Enforcement Authority~~CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the BES interrupting device operation occurred prior to the current audit period.

If a Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System 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~~The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking
 Compliance Investigation
 Self-Reporting
 Complaint
 Periodic Data Submittal

1.4. Additional Compliance Information

~~Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC 004—Attachment 1 to the CEA within two calendar months following the end of each calendar quarter.~~

~~The CEA will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.~~

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–and~~ 1.32 in more than 120 calendar days but less than or equal to ~~130~~150 calendar days of the operation’s occurrence. OR The responsible entity	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–and~~ 1.32 in more than ~~130~~150 calendar days but less than or equal to ~~140~~160 calendar days of the operation’s occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–and~~ 1.32 in more than ~~140~~160 calendar days but less than or equal to ~~150~~170 calendar days of the operation’s occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–and~~ 1.32 in more than ~~150~~170 calendar days of the operation’s occurrence. OR The responsible entity failed to identify and

		identified a Protection System operation that operated one of its <u>BES</u> interrupting devices but failed to review the operation in accordance with Requirement R1, Part 1.1. OR The responsible entity completed its review of a Protection System ~~Operation~~ operation that operated one of its <u>BES</u> interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to document the findings in accordance with Requirement R1, Part 1.~~32~~.			review a Protection System operation that operated one of its <u>BES</u> interrupting devices in accordance with Requirement R1, Part 1.1. OR ~~The responsible entity completed its review of a Protection System operation that operated one of its interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to designate the operation as a Misoperation in accordance with Requirement R1, Part 1.2.~~ OR The responsible entity failed to investigate a Misoperation and document the findings in accordance with Requirement R1, Part 1.~~32~~.

						OR The ~~responsible~~ entity ~~completed its investigation of a~~ <u>that owns the BES</u> ~~interrupting device but does not own the entire~~ Protection System ~~Operation that operated one of its interrupting devices in 120 calendar days and suspected that another entity's could not determine if the operation was correct and failed to notify the other owner(s) of the~~ Protection System component ~~contributed to the Misoperation, and failed to notify(s)~~ and provide <u>any</u> requested investigative information ~~to that entity~~ in accordance with Requirement R1, Part 1.1.
R2	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, more

PRC-004-3 — Protection System Misoperation Identification and Correction

			more than 60 calendar days but less than or equal to 70 calendar days following the ~~completion~~ <u>identification</u> of the ~~investigation or receiving notification~~ <u>cause of the Misoperation</u> .	more than 70 calendar days but less than or equal to 80 calendar days following the ~~completion~~ <u>identification</u> of the ~~investigation or receiving notification~~ <u>cause of the Misoperation</u> .	more than 80 calendar days but less than or equal to 90 calendar days following the ~~completion~~ <u>identification</u> of the ~~investigation or receiving notification~~ <u>cause of the Misoperation</u> .	than 90 calendar days following the ~~completion~~ <u>identification</u> of the ~~investigation or receiving notification~~ <u>cause of the Misoperation</u> . OR The responsible entity failed to develop a CAP or make a declaration in accordance with Requirement R2.
R3	Operations Planning, Long-Term Planning	Medium	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 180 calendar days but less than or equal to ~~190~~ <u>210</u> calendar days following the associated <u>BES</u> interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than ~~190~~ <u>210</u> calendar days but less than or equal to ~~200~~ <u>220</u> calendar days following the associated <u>BES</u> interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than ~~200~~ <u>220</u> calendar days but less than or equal to ~~210~~ <u>230</u> calendar days following the ~~completion of the investigation~~ <u>associated BES interrupting device operation</u> .	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, more than ~~210~~ <u>230</u> calendar days following the ~~completion of the investigation~~ <u>associated BES interrupting device operation</u> . OR The responsible entity failed to develop; ~~implement, and document~~ an action plan; or a declaration in

PRC-004-3 — Protection System Misoperation Identification and Correction

						accordance with Requirement R3.
R4	Operations Planning, Long-Term Planning	High	The responsible entity <u>failed to revise maintained records of a CAP or action plan as needed in accordance with Requirement R4.</u> ~~but the records were incomplete.~~	<u>N/A</u>	<u>N/A</u>	The responsible entity failed to implement a CAP or action plan <u>in accordance with Requirement R4.</u> OR The responsible entity ~~failed to maintain records of a CAP or action plan.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

The composite Protection System in the context of this standard is the total complement of protection for a system Element. All protection for a given Element such as primary, secondary, backup, pilot and non-pilot relay schemes are included in the composite Protection System for the Element. These individual schemes or systems may be isolated or function independently, but aggregate as part of one composite Protection System.

A Protection System is defined in the NERC Glossary of Terms as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Circuit breaker and other interrupting device mechanisms are not part of a Protection System.

A revised Misoperation definition is being proposed for industry adoption. ~~It; the failure of an Element's composite Protection System to operate as intended.~~ The definition includes the following ~~conditions; categories:~~

(1) A failure of a Protection System to operate for a Fault within the zone it is designed to protect. ~~A lack of target information, e.g. when a high-speed pilot system does not trip because a high-speed zone element trips first, is not a Misoperation. If a fault or abnormal condition is cleared within the time normally expected with proper functioning of at least one Protection System element, then failure of another Protection System element associated with the protection scheme is not a Misoperation.~~ **The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct.**

A failure of a transformer's composite Protection System to operate for a transformer Fault is an example of a "failure to trip" Misoperation. This type of Misoperation typically results in the Fault being cleared by remote backup Protection System operations.

A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "failure to trip" Misoperation as long as another component of the transformer's composite Protection System operated to clear the Fault. Please see category 3 to see if the "slow trip" classification applies to the operation.

A lack of target information, e.g. when a high-speed pilot system does not target because a high-speed zone element trips first, does not by itself constitute a Misoperation.

(2) A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. ~~For example, The failure to trip the generator by loss of field protection for a loss of field condition on that generator~~ **Protection System component is not a Misoperation: as long as the overall performance of the Protection System for the Element it is designed to protect is correct.**

A failure of a generator's composite Protection System to operate for a loss of field condition is an example of a "failure to trip" Misoperation. This type of Misoperation may require manual operator intervention.

A failure of a "primary" reverse power relay (or any other component) is not a "failure to trip" Misoperation as long as another component of the generator's composite Protection System operated to shut down the generator. Please see category 4 to see if the "slow trip" classification applies to the operation.

The non-Fault conditions cited in the definition are examples only, and do not constitute an all inclusive list.

(3) A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed ~~f~~**F**ault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance ~~is has~~ **not required by planning studies associated with** been identified to meet the dynamic stability performance requirements of the TPL standards ~~or by~~ **nor is it required to ensure** ~~coordination requirements with other Protection Systems.~~

A failure of a line's composite Protection System to operate as quickly as intended for a line Fault is an example of a "slow trip" Misoperation. This type of Misoperation typically results in remote backup Protection System operations before the Fault is cleared.

In many cases, high-speed protection is installed as part of the utility's standard practice without having the need for high-speed protection for meeting TPL requirements. A slow trip of this Protection System would not negatively impact the dynamic performance of the BES; so, it does not need to be reported. However, even if high-speed clearing is not required, the Protection Systems must coordinate to prevent an "unnecessary trip" Misoperation (e.g. an over trip).

The phrase "slower than intended" means the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System operation was adequate.

The reference to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent dynamic instability. The performance requirements in the TPL standards are found in Table 1, and are applicable to all contingencies mentioned for Type A, B and C contingencies.

Coordination with other Protection Systems refers to the need to ensure that relaying operates in the proper or planned sequence (i.e. the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

(4) A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which it was intended to operate. ~~An example of this type of Misoperation is an over excitation condition where the protection designed to detect this condition operated slower than intended resulting in a higher degree of insulation stress than desired.~~

A failure of a generator's composite Protection System to operate as quickly as intended for an over excitation condition is an example of a "slow trip" Misoperation. This type of Misoperation may result in equipment damage.

The phrase "slower than intended" means the composite Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.

The non-Fault conditions cited in the definition are examples only, and do not constitute an all inclusive list.

(5) A Protection System operation for a Fault for which the Protection System is not intended to operate, ~~excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.~~

~~An example of operation of a transformer's composite Protection System which over trips for a properly cleared line Fault is an example of an "unnecessary trip" Misoperation. For this type of Misoperation is an over-reaching trip due to a lack of coordination between remote and local Protection Systems. Note: Operation of, the Fault is typically cleared properly by the faulted equipment's composite Protection System (line relaying, in this case) without the need for an external Protection System's operation.~~

An operation of a properly coordinated remote Protection Systems is not a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the local Protection System to clear the Fault in adjacent zones is not. An interrupting device failure, a "failure to trip" Misoperation of the, or a "slow trip" Misoperation may result in a proper remote Protection System if the local Protection System of the faulted Element

~~fails to clear the Fault within the intended time; however, the failure of the local Protection System for the faulted zone is a Misoperation.~~

(6) A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate. These non-Fault conditions are unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.

~~Non-Fault conditions may include but are not limited to power swings, over excitation or, loss of excitation but could include even, frequency excursions and normal conditions. For example,~~

~~An operation of a line's composite Protection System due to a relay failure during normal conditions could conceivably cause an incorrect example of an "unnecessary" trip and a other than Fault" Misoperation.~~

In a second example, tripping a generator by the operation of loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation. In a third example, an impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because it was set with an excessive reach that unnecessarily restricted the line's load carrying capability. ~~This category of Misoperation cannot address at this time other operations during power swings unless the relay is clearly improperly set. Additional clarity on this specific issue will need to await completion of Phase III of Project 2010-13 on Relay Loadability which will address protective relay operations due to power swings as directed by FERC Order No. 733. Finally, an example of an operation that is not a Misoperation under this category is an unintended operation as a result of on-site maintenance, testing, construction or commissioning.~~

An operation that occurs during a non-fault condition but was initiated by on-site maintenance, testing, inspection, construction or commissioning is not a Misoperation. However, once the maintenance, testing, inspection, construction or commissioning has been completed, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of the technical personnel.

This definition is based on the established IEEE/PSRC I3 Working Group on 'Transmission Protective Relay System Performance Measuring Methodology' categories (excluding Failure to Reclose) of Relay System Misoperation. The phrase abnormal condition has been replaced with "non-fault condition" to remove ambiguity.

The exclusion of a component failure, as long as the composite Protection System operates correctly, was based on recommendations by the NERC SPCS. Entities still need to review each Protection System operation. Covering these types of component failures within the standard constitutes additional administrative burden for types of failures that have no immediate reliability impacts.

Failure to automatically reclose after a Fault is not included as a Misoperation because reclosing equipment is not included under the definition of Protection Systems.

~~Interrupting Device~~ BES interrupting device operations which are initiated by ~~control systems~~ non-protective functions, such as those associated with generator controls, or

Application Guidelines

turbine/boiler controls, Static VAR Compensators (SVCs), Flexible AC Transmission Systems (FACTS), High-Voltage DC (HVDC) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. Additionally, operations initiated by control functions within protective relays are not considered Protection System operations. For example, in cases where a component of the Protection System or a function of a component within the Protection System is used for control of a generator, such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard. Automation (e.g. data collection) is also not a protective function and is not subject to this standard.

A generator Protection System operation prior to closing the unit breaker(s) is not considered a Misoperation—provided no in-service BES Elements are tripped. These types of operations are excluded because when the generating unit is not synchronized and is isolated from the BES. Protection System operations which occur with the protected Element out of service, that do not trip any in-service Elements are not Misoperations. Protection System operations unrelated to on-site maintenance, testing, inspection, construction or commissioning activities which occur with the protected Element out of service, that trip any in-service Elements are Misoperations.

In some cases where zones of protection overlap, the owner of BES Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element. For example, the high side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high side of the transformer and into its primary winding. -In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high side of the connected transformer. Therefore, the operation of the line relaying for a high side transformer Fault would not be considered a Misoperation.

This standard addresses the reliability issues identified in the letter¹ from Gerry Cauley, NERC President and CEO, dated January ~~17, 2010~~ 17, 2011. “Nearly all major system failures include misoperation of relays as a factor contributing to the propagation of the events..... Reducing the risk to reliability from relay Misoperations requires consistent collection of misoperation information by regional entities, along with systematic analysis and correction of the underlying causes of preventable Misoperations.” The standard also addresses the findings in the 2011 Risk Assessment of Reliability Performance²; July 2011 “....a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry.”

¹ http://www.nerc.com/news_pr.php?npr=723

² http://www.nerc.com/files/2011_RARPR_FINAL.pdf

Application Guidelines

In the event of a natural disaster, note that the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

Requirement R1

This requirement promotes the prudent evaluation of ~~all~~each Protection System operations ~~to designated~~determine if the operation was correct or a Misoperation, even those Misoperations, ~~even those~~ difficult to detect. Unless all BES Protection System operations and Faults that challenge them are reviewed, it cannot be determined with certainty that all Misoperations are identified. For example, if you only reviewed ~~Faults~~operations resulting in an overtrip, you would not necessarily identify Misoperations caused by slow trips.

Requirement ~~4~~R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. - The ~~SDT~~drafting team believes the owner of the BES interrupting device that operated would be in the best position to analyze the Protection System operation, determine if a Misoperation occurred, and perform the initial investigation to determine the cause of the Misoperation. If the BES interrupting device owner ~~suspects~~does not own all of the Protection System and cannot determine that the ~~Misoperation~~Protection System operation was ~~caused by a~~correct, then notify the other owner(s) of the Protection System component ~~owned by another entity, they must notify that component owner and document the notification(s) and provide any requested investigative information.~~ In this case, it is expected that both entities will work together to investigate the cause of the operation.

Protection Systems are made of many components. These components may be owned by more than one entity. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken. If an entity feels it cannot get the level of cooperation it needs to adequately address a Misoperation, the entity should appeal to its Regional Entity for help in resolving the situation.

Determining the cause of Protection System Misoperations is essential in developing an effective remedy to avoid future Misoperations. ~~The SDT~~The drafting team recognizes that there may be multiple causes for a Misoperation; in these circumstances the CAP would include a remedy for the identified causes. The 60 day clock for developing the CAP will be associated with the determination of the first cause. A CAP can be revised if additional causes are found. The drafting team believes 120 calendar days is a reasonable period of time to investigate operations, determine the cause for most Misoperations and document findings in ~~an~~a Misoperation investigation report. This time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal.

Application Guidelines

Regardless of whether a cause is identified, the BES interrupting device owner must document the investigation as a potential aid in possible future Misoperation investigations. If a single Protection System causes multiple BES interrupting device owners to be affected, the entities may work together to produce a common Misoperation investigation report. Similarly, if the BES interrupting device owner and the Protection System component owner that caused a Misoperation are different entities, they may work together to produce a common report. ~~Each TO, GO, or DP would be expected to have a copy of the common investigation report.~~

~~A~~A Misoperation investigation report or documented findings may include the following information: 1) initial evidence, 2) probable causes, 3) tests and studies, and 4) conclusions. A brief description of the event surrounding the Misoperation may be included if not separately documented. The initial evidence, which may also be documented separately, contains the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records ~~as appropriate~~. Probable causes are those causes which are most likely to have contributed to the Misoperation and could be considered for further testing. The test and studies documented in the report would describe and provide findings of those tests if the entity was able to perform them during the initial investigation phase (e.g. relay calibration and simulation tests, communication noise and attenuation tests, CT/VT ratio tests, DC continuity checks and functional tests) and studies (e.g. short circuit and coordination studies) performed in the attempt to determine the cause. The conclusions should summarize the cause(s) substantiated by the evidence and findings of the tests and studies.

Requirement ~~2~~R2

If the Misoperation cause is identified within 120 days of the event, Requirement R2 requires Protection System owners to develop a CAP or to make a declaration of no additional action within 60 calendar days of determining the cause. The drafting team recognizes there may be multiple causes for a Misoperation; in these circumstances the CAP would include a remedy for the identified causes. The 60 day clock for developing the CAP will be associated with the determination of the first cause. A CAP can be revised if additional causes are found. Based on industry experience and operational coordination timeframes, the ~~SDT~~drafting team believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, or development of a schedule ~~or procurement of funds~~ for a CAP, or to prepare a declaration justifying the lack of a CAP.

The 120 day time period and the 60 day time period are distinct and within the context of Requirement R1 and Requirement R2 respectively, need to remain separate. With the ultimate goal of keeping the implementation time of a CAP as short as possible, if a cause of a Misoperation is determined quickly the CAP creation timeframe (60 days) becomes applicable and requires the CAP implementation be less than 180 days. Also, if the interrupting device owner is tardy in informing another Protection System component owner and using up much of the 120 day period, it still leaves a considerable amount of time (at least 60 days) to develop an action plan for further investigation by the Protection System component owner, or if a cause is determined the creation of the CAP.

Application Guidelines

Where there are multiple Protection System owners involved in a Misoperation, the one or more owners whose Protection System component(s) contributed to the Misoperation will create a CAP or declaration as required by Requirement 2R2. Owners whose Protection System components operated correctly do not need to create a CAP. ~~All owners should update their investigation documentation to indicate which party or parties are performing a CAP to address the Misoperation.~~

Resolving Misoperations benefits the Protection System owner and the BES by ~~improving~~maintaining reliability and security. The CAP is an established tool for resolving operational problems. The NERC Glossary of Terms defines a Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem".

Protection System owners are expected to exercise due diligence in the development and implementation of a CAP. Typically included would be any corrective actions taken to prevent recurrence (along with the date performed), ~~and any corrective actions planned to be taken to prevent recurrence (along with the planned date)-),~~ and an evaluation of the CAP's applicability to other Protection Systems owned by the entity.

~~An example of a CAP for a Misoperation determined the CAP's applicability to have been caused other Protection Systems owned by the entity is intended to encourage diligence in preventing similar Misoperations. The Protection System owner is responsible for determining the scope of the problem, and for including appropriate actions in the CAP. The evaluation may result in adding preemptive actions to the CAP. The CAP is complete when all specified actions are completed.~~

The following are examples of Corrective Action Plans (CAPs):

CAP Example 1 – Corrective actions for a failed relay that has not been repaired might be: "Temporarily only:

The impedance relay was removed failed relay from service on xx/xx/xx. Plan to repair then return 6/2/12 because it was applying a standing trip. Relay testing was performed on 6/4/12. A failed capacitor was found within the impedance relay. The capacitor was replaced on 6/5/12. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on xx/xx/xx." 6/5/12.

An example of a CAP for a Misoperation determined to have been caused by Applicability to other Protection Systems: Undesired trips of this type of impedance relay due to capacitor failures have occurred only occasionally within our system. This type of impedance relay is gradually being replaced with microprocessor relays as Protection Systems are modernized. It is therefore our assessment that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for our system.

CAP Example 2 - Corrective actions for a failed relay that has been repaired might be: "Temporarily, and a program for preemptive actions at similar installations:

The impedance relay was removed ~~failed relay~~ from service on xx/xx/xx. Repaired then returned relay 6/2/12 because it was applying a standing trip. Relay testing was performed on 6/4/12. A failed capacitor was found within the impedance relay. The capacitor was replaced on 6/5/12. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on xx/xx/xx."6/5/12.

An example Applicability to other Protection Systems: Undesired trips of this type of impedance relay due to capacitor failures have occurred frequently. It is therefore our assessment that a program should be established by 12/1/12 for wholesale preemptive replacement of capacitors in this type of impedance relay.

A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/12.

CAP Example 3 - Corrective actions for a Misoperation suspected to have been caused by an intermittent relay failure might be: "Temporarily failed relay; and preemptive actions for similar installations:

The impedance relay was removed ~~suspect relay~~ from service on xx/xx/xx. Replaced with like kind, and placed in 6/2/12 because it was applying a standing trip. Relay testing was performed on 6/4/12. A failed capacitor was found within the impedance relay. The capacitor was replaced on 6/5/12. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on xx/xx/xx."6/5/12.

Applicability to other Protection Systems: Undesired trips of this type of impedance relay due to capacitor failures have occurred frequently. It is therefore our assessment that preemptive replacement of capacitors in this type of impedance relay should be pursued.

It is planned to replace the impedance relay capacitors at stations A, B, and C by 9/1/12. It is planned to replace the impedance relay capacitors at stations D, E, and F by 11/1/12. It is planned to replace the impedance relay capacitors at stations G, H, and I by 2/1/13.

The impedance relay capacitor replacement was completed at stations A, B, and C on 8/16/12. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/26/12. The impedance relay capacitor replacement was completed at stations G, H, and I on 1/9/13.

CAP Example 4 - Corrective actions for a firmware problem; and preemptive actions for similar installations:

Fault records were provided to the manufacturer on 6/4/12. On 6/11/12, the manufacturer responded that the misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 6/12/12.

Applicability to other Protection Systems: Based on our risk assessment, we plan to install firmware version 3 at all of our installations that are determined to be version 2. Proposed completion date is 12/31/12.

The firmware replacements were completed on 12/4/12.

If the Misoperation cause is identified within 120 days, and no corrective action has been or is intended to be taken, Protection System owners are required to make a declaration to this effect. A "no CAP declaration" would typically include the Misoperation cause and justification for taking no corrective action.

An example of a "no CAP declaration" due to BES reliability might be: "The investigation showed the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Our studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations." A "no CAP declaration" due to BES reliability is expected to be used sparingly.

~~CAPs should include an evaluation as to whether the entity's Protection Systems at other locations are also vulnerable to the same type of Misoperation.~~

Requirement 3

There are some cases where a Misoperation cause is outside of an entity's control and would result in a "no CAP declaration." Items that may be considered outside of an entity's control could be a non-registered entity communications provider problem or a transmission transformer tapped industrial customer who initiates a direct transfer trip to a registered entity's transmission breaker. Generally, situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control. The "outside an entity's control" declaration is expected to be used sparingly.

Requirement R3

If the Misoperation cause is not identified within 120 days, and reasonable investigative actions have not been exhausted, Protection System owners are expected to exercise due diligence in the development and implementation of an action plan for additional investigation. This action plan would typically include any investigative actions taken to determine the cause (along with the date performed), and any investigative actions planned to be taken to determine the cause (along with the planned date).

At the end of 180 days, the Protection System owner must have an action plan or a declaration why no further actions will be taken. The action plan does not need to have been implemented within the 180 days, but it must have been developed within this time frame. The 180 calendar days ~~is~~are the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)

Application Guidelines

Where there are multiple Protection System owners involved in a Misoperation and no cause has been determined, then each Protection System owner must either develop an action plan or declare why no further actions will be taken.

An example of an investigative action plan for more testing might be: "All relays at station A functioned properly during testing on xx/xx/xx. An outage is required to test the relays at station B. The outage is scheduled for xx/xx/xx."

An example of an action plan for adding monitoring might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. It is planned to install a temporary DFR at station A on xx/xx/xx and to monitor the currents for at least 3 months."

An example of an action plan for reviewing relay settings might be: "All relays at station A functioned properly during testing on xx/xx/xx. All relays at station B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. It is planned to complete a relay settings review by xx/xx/xx."

If the Misoperation cause is not identified and reasonable investigative actions have been exhausted within 180 days, Protection System owners are required to make a declaration to this effect. A "no action plan" declaration would typically include any investigative actions taken to determine the cause (along with the date performed), and justification for taking no additional investigative actions.

An example of a "no action plan" declaration might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. The carrier coupling equipment functioned properly during testing on xx/xx/xx. A settings review completed on xx/xx/xx indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be proper, and the equipment at station A and station B is already monitored, we have decided to close this investigation."

Requirement R4

~~Finally, the~~The goal of the standard has not been met unless ~~CAP(s)~~CAPs or action plans are actually implemented, as is required in Requirement R4. The responsible entity is required to implement and complete a CAP or action plan to accomplish the purpose of this standard, which is to prevent future Misoperations, thereby minimizing risk to the BES. The responsible entity is also required to complete the CAP or action plan, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

The goal of an action plan created in Requirement R3 is to determine a cause so a CAP can be created to ultimately remedy the cause of the Misoperation. If the cause is determined as a result of the action plan, the entity must develop a CAP or a declaration within 60 days of determination of cause per Requirement ~~2R2~~. This requirement sets the expectation that the work identified in the CAP or action plan will be completed on schedule as planned. Deferrals or other relevant changes to the CAP or action plan need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of successful CAP or action plan execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of

planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports or other evidence.

Documentation of a CAP or action plan provides an auditable progress and completion confirmation for specific Misoperations. In addition, the investigative documentation may aid the responsible entity in remedying future Misoperations of a similar nature.

Reporting:

~~A review of the Transmission Availability Data System (TADS) data for the years 2008—2010 revealed that the fourth-ranked initiating cause of BES outages not related to weather was “Failed Protection System Equipment.” Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.~~

~~Section C-1.4 requires periodic data reporting and references a common reporting format to facilitate consistent reporting of Misoperation data by all Transmission Owners, Generator Owners, and Distribution Providers. Reporting Misoperation data in a common format permits the ERO to analyze the data, develop meaningful metrics for measuring Protection System performance, identify trends in Protection System performance that negatively impact reliability, and identify lessons learned.~~

~~Analysis of data from all Misoperations across North America makes possible identification of issues and trends that may not be identifiable through analysis of smaller data sets on an entity or regional basis. Information regarding identified issues and trends and recommended actions will be shared with Transmission Owners, Generator Owners, and Distribution Providers through lessons learned or industry alerts. Sharing this information will permit recipients to take appropriate actions to drive improvements in Protection System performance.~~

~~The common reporting template also will improve the usefulness of metrics developed to track Protection System performance. While the most relevant category defined in TADS is titled “Failed Protection System Equipment,” the title is not an accurate description of the information reported in the metric. This metric includes all Protection System Misoperations that are not related to human error, which is only a subset of all Protection System Misoperations. The Protection System Misoperations related to human error (e.g., miscoordinated settings, incorrect setting calculations, and errors in applying settings to the relay, etc.) are tracked separately from Protection System equipment related Misoperations, and are grouped together with other human errors by a utility employee or contractor. Similarly, Protection System Misoperations related to failed equipment such as a failed CVT on the primary insulation side are reported under “Failed AC Substation Equipment.” Reporting of Misoperations data using the common format specified in C-1.4 will permit development of metrics specific to Protection System Misoperations, with the potential to break down the metric by category of Misoperation (e.g., failure to trip, slow trip, unnecessary trip, etc.) and cause of Misoperation (ac system, dc system, as-left personnel error, incorrect setting/logic/design, and relay failures/malfunctions).~~

~~Reporting Misoperations and their CAPs or action plans provides a means of monitoring and assessing Misoperations. Reviewing and tracking this information provides a method~~

Application Guidelines

of validating the actions taken to address the causes of Misoperations. A second need for reporting Misoperations is to facilitate the identification of trends in Protection System performance that negatively impact reliability. Analyzing data from all Misoperations across North America will make it possible to identify trends that may not be discernible through analysis of smaller data sets on an entity or regional basis.

Misoperations and updates will be submitted to the Regional Entity on a quarterly basis per the following schedule:

Reporting Quarter	Submission Date
1st Quarter (Jan 1—March 31)	May 31
2nd Quarter (Apr 1—June 30)	August 31
3rd Quarter (July 1—Sept 30)	November 30
4th Quarter (Oct 1—Dec 31)	February 28

The two calendar months reporting of Misoperations that occurred within the quarterly reporting period corresponds to the recommendations provided by ERO RAPA and also correlates to the time which the majority of Regional Entities were using in 2011. It is believed that two calendar months is a reasonable time for an entity to submit their Misoperations data after the close of a reporting period. Reporting and updating on a limited time interval and lag (from occurrence) aids in focusing on high trend items of common mode failures. A longer period of time for reporting could prevent high trend failures from being quickly recognized.

Examples of reporting:

1. If a Misoperation occurred on March 30 but was not identified as a Misoperation until June 2, then this Misoperation would be reported in the second quarter reporting period.
2. If the Misoperation in example 1 was not completely investigated in the second quarter but a cause was determined on July 2, then a resubmittal should be reported in the third quarter.
3. If the Misoperation in examples 1 and 2 had its CAP completed on November 2, then a resubmittal indicating that the CAP was completed should be reported in the fourth quarter.

Mapping Document

Project 2010-05.1 Protection Systems: Phase 1(Misoperations)

~~Mapping Document~~

Mapping Document Showing Translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, and PRC-004-2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into PRC-004-3 — Protection System Misoperation Identification and Correction.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	4.1. Functional Entities: 4.1.1 Transmission Owner 4.1.2 Generator Owner 4.1.3 Distribution Provider

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment
R1. Part 1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	PRC-004-3 Applicability Section 4.2 Facilities.	4.2. Facilities 4.2.1 Protection Systems for <u>BES</u> Facilities 4.2.2 <u>Underfrequency Load Shedding (UFLS)</u> that ~~are part of the trips a~~ <u>BES Element</u> ~~4.2.2—Facilities not included~~ ~~4.2.2.13~~ Special Protection Systems (SPS) ~~or~~ Remedial Action Schemes (RAS) ~~4.2.2.2), and~~ Undervoltage Load Shedding (UVLS) <u>are excluded</u> ~~4.2.3—Relay functions not included (these are non~~4.2.4 <u>Non</u>-protective functions that may be imbedded within a Protection System) ~~4.2.3.1 Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples)~~ ~~4.2.3.2 Automation (e.g. data collection) are excluded~~
R1. Part 1.2. Data reporting requirements (periodicity and format) for Misoperations.	~~PRC-004-3~~ <u>Compliance</u> NERC Rules of <u>Procedure</u> , Section ~~C-1.4~~ <u>Additional Compliance</u>	~~C-1.4. Additional Compliance Information~~ ~~Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004—Attachment 1~~

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment
	~~Information~~ <u>1600 data request</u>	~~to the CEA within two calendar months following the end of each calendar quarter.~~ ~~The CEA will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.~~ <u>N/A</u>
R1. Part 1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	R1. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall:~~ Within 120 calendar days of ~~ana BES~~ interrupting device operation in its Facility caused by a Protection System operation, ~~each Transmission Owner, Generator Owner, and Distribution Provider shall:~~ <u>1.1 1.1 Identify</u> identify and review each Protection System operation. • If the entity ~~suspects a owns~~ both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation • If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment
		<u>owner(s) of the</u> Protection System component(s) ~~owned by another entity contributed to a~~ Misoperation, ~~notify the owner of that Protection System component~~ and provide any requested investigative information. ~~1.2 Designate each Misoperation (if any).~~ ~~1.3 Investigate each~~ <u>The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.</u> <u>1.2 Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation (if any) shall investigate and document the findings including a cause for each Misoperation including a cause, if identified.</u> R2. ~~Within 60 calendar days of identifying the cause(s) of each Misoperation, the~~ <u>Each</u> Transmission Owner, Generator Owner, or Distribution Provider shall, <u>within 60 calendar days of identifying the cause of each Misoperation:</u>

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment
		- Develop ~~and document~~ a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or - Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. R3. ~~For each Misoperation without an identified cause(s), the~~ <u>Each</u> Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of ~~its~~<u>the</u> associated <u>BES</u> interrupting device operation, complete <u>for each Misoperation without an identified cause</u>: - Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or - A declaration explaining why no further actions will be taken. R4. ~~For each CAP or action plan, the~~ <u>Each</u> Transmission

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment
		Owner, Generator Owner, or Distribution Provider shall: ~~4.1 Implement the CAP or action plan~~ 4.2 ~~Maintain detailed implementation records of~~ <u>implement</u> each CAP or action plan ~~including dated information surrounding any revision(s), and revise as needed through~~ completion.
R1. Part 1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	4.1. Functional Entities: 4.1.1 Transmission Owner 4.1.2 Generator Owner 4.1.3 Distribution Provider
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns	PRC-004-3 is a results-based standard that achieves the reliability objectives of PRC-003-1. The requirements in the standard define the process for the responsible

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment
review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	entities to follow. The standards development process mandates the standards be reviewed once every five years. 4.1. Functional Entities: 4.1.1 Transmission Owner 4.1.2 Generator Owner 4.1.3 Distribution Provider See PRC-004-3
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	PRC-004-3 is a results-based standard that achieves the reliability objectives of PRC-003-1. The requirements in the standard define the process for the responsible entities to follow. 4.1. Functional Entities: 4.1.1 Transmission Owner 4.1.2 Generator Owner 4.1.3 Distribution Provider See PRC-004-3

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	R1.– <u>Each Transmission Owner, Generator Owner, and Distribution Provider shall:</u> Within 120 calendar days of ~~an~~ <u>a BES</u> interrupting device operation in its Facility caused by a Protection System operation, ~~each Transmission Owner, Generator Owner, and Distribution Provider shall:~~ <u>1.1 1.1 Identify</u> identify and review each Protection System operation. • <u>If the entity ~~suspects~~ owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation</u> • <u>If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) ~~owned by another entity contributed to a Misoperation, notify the owner of that Protection System component~~ and provide any requested investigative information.</u>

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment
		~~1.2 Designate each Misoperation (if any).~~ ~~1.3 Investigate each~~ <u>The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.</u> <u>1.2 Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation (if any) shall investigate and document the findings including a cause for each Misoperation including a cause, if identified.</u> R2. ~~Within 60 calendar days of identifying the cause(s) of each Misoperation, the~~ <u>Each</u> Transmission Owner, Generator Owner, or Distribution Provider shall, <u>within 60 calendar days of identifying the cause of each Misoperation:</u> Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment
		includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or - Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. R3. ~~For each Misoperation without an identified cause(s), the~~<u>Each</u> Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of ~~its~~<u>the</u> associated <u>BES</u> interrupting device operation, complete <u>for each Misoperation without an identified cause</u>: - Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or - A declaration explaining why no further actions will be taken. R4. ~~For each CAP or action plan, the~~<u>Each</u> Transmission Owner, Generator Owner, or Distribution Provider

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment
		shall: ~~4.1 Implement the CAP or action plan~~ ~~4.2 Maintain detailed implementation records of~~ <u>implement</u> each CAP or action plan ~~including dated information surrounding any revision(s),~~ and <u>revise as needed through</u> completion.
R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	R1. <u>Each Transmission Owner, Generator Owner, and Distribution Provider shall:</u> Within 120 calendar days of ~~an~~ <u>a BES</u> interrupting device operation in its Facility caused by a Protection System operation, ~~each Transmission Owner, Generator Owner, and Distribution Provider shall:~~ ~~1.1 1.1 Identify~~ <u>identify</u> and review each Protection System operation. <u>If the entity ~~suspects~~ owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation</u> <u>If the entity owns the BES interrupting device but does not own all of the Protection System</u>

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment
		<u>and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the</u> Protection System component(s) ~~owned by another entity contributed to a Misoperation, notify the owner of that Protection System component and~~ provide any requested investigative information. ~~1.2 Designate each Misoperation (if any).~~ ~~1.3 Investigate each~~ <u>The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.</u> <u>1.2 Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation (if any) shall investigate and document the findings including a cause for each Misoperation including a cause, if identified.</u>

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment
		R2. ~~Within 60 calendar days of identifying the cause(s) of each Misoperation, the~~ <u>Each</u> Transmission Owner, Generator Owner, or Distribution Provider shall, <u>within 60 calendar days of identifying the cause of each Misoperation:</u> • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. R3. ~~For each Misoperation without an identified cause(s), the~~ <u>Each</u> Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of its associated interrupting device operation, complete <u>for each Misoperation without an identified cause:</u> • Development of an action plan that identifies

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment
		any additional investigative actions and/or Protection System modifications, including a work timetable, or A declaration explaining why no further actions will be taken. R4. ~~For each CAP or action plan, the~~<u>Each</u> Transmission Owner, Generator Owner, or Distribution Provider shall: ~~4.1 Implement the CAP or action plan~~ ~~4.2 Maintain detailed implementation records of~~<u>implement</u> each CAP or action plan ~~including dated information surrounding any revision(s),~~ and <u>revise as needed through</u> completion.
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional	PRC-004-3 Requirement 4 ~~Compliance~~<u>NERC Rules of Procedure, Section C-1.4</u> ~~Additional Compliance Information~~<u>1600 data request</u>	R4. ~~For each CAP or action plan, the~~<u>Each</u> Transmission Owner, Generator Owner, or Distribution Provider shall: ~~4.1 Implement the CAP or action plan~~ ~~4.2 Maintain detailed implementation records of~~<u>implement</u> each CAP or action plan ~~including dated information surrounding any revision(s),~~ and <u>revise</u>

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment
Entity's procedures.		<u>as needed through</u> completion. ~~C.1.4. Additional Compliance Information~~ Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 Attachment 1 to the CEA within two calendar months following the end of each calendar quarter. The CEA will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis. <u>N/A</u>

Implementation Plan

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standards drafting team proposes modifying the following approved definition:

Misoperation: ~~Any of the following:~~

The failure of an Element's composite Protection System to operate as intended.

Any of the following is considered a Misoperation:

- 1. Failure to Trip - During Fault** - A failure of a Protection System to operate for a Fault within the zone it is designed to protect. ~~{The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an the Element it is designed to protect is correct.}~~
- 2. Failure to Trip - Other Than Fault** - A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. ~~{The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an the Element it is designed to protect is correct.}~~
- 3. Slow Trip - During Fault** - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. ~~{Delayed Fault Cclearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance is requiredhas not been identified to meet the dynamic stability performance requirements of the TPL standards or bynor is it required to ensure coordination requirements-with other Protection Systems.}~~
- 4. Slow Trip - Other Than Fault** - A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.

5. **Unnecessary Trip - During Fault** - A Protection System operation for a Fault for which the Protection System is not intended to operate, ~~excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.~~
6. **Unnecessary Trip - Other Than Fault** - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.

Background

PRC-004-3 Protection System ~~Misoperations~~ Misoperation Identification and Correction is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In ~~the NOPR~~ FERC Order No. 693, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The ~~NOPR~~ Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

General Considerations

PRC-004-WECC-1 – This regional standard is related to reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for ~~Facilities that are part of the BES~~ BES Elements.
- ~~Facilities not included~~
- Underfrequency Load Shedding (UFLS) that trips a BES Element
- ~~Special Protection Systems (SPS) or~~ Remedial Action Schemes (RAS)

- ~~), and~~ Undervoltage Load Shedding (UVLS)
- ~~Relay functions not included (these are nonexcluded~~
- ~~Non~~-protective functions that may be imbedded within a Protection System ~~are excluded~~
- ~~Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples)~~
- ~~Automation (e.g. data collection)~~

Effective Date of New or Revised Standards and Definitions

First day of the first calendar quarter that is ~~six~~twelve months beyond the date that PRC-004-3 is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is ~~six~~twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The proposed definition of Misoperation shall become effective on the same date as PRC-004-3. Entities shall use this definition when implementing any portions of Requirements R1, R2 R3 and R4 that use this defined term.

Implementation Plan for Requirements R1, R2, R3 and R4

Entities shall be 100% compliant for any new Protection System Operation on the first day of the first calendar quarter ~~six~~twelve months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ~~six~~twelve months following Board of Trustees adoption. Protection System operations that occur before the compliance date shall comply with the previous version of the Standard.

Retirement of Existing Standards

The existing standards PRC-003-1 and PRC-004-2a shall be retired at midnight of the day immediately prior to the effective date of PRC-004-3.

Project 2010-05.1 – PRC-004-3: Protection System Misoperations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-004-3 — Protection System Misoperations.

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.

The Protection System Misoperations Standard Drafting Team 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. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines**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.

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.

PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

|

|

PRC-004-3 has four (4) requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1. The revised standard requires entities to identify and review Protection System operations and designate each Misoperation; then investigate each Misoperation and document the findings. If a cause is identified, the entity either creates a Corrective Action Plan (CAP) or writes a declaration that they cannot correct the misoperating device(s). If a cause is not identified, the entity either creates an action plan for additional investigation or a writes a declaration that no further work will be done. The next step is to implement and complete the CAP or action plan. If the action plan leads to the determination of a cause, then the entity would either create a Corrective Action Plan (CAP) or write a declaration. The requirements recognize and encompass the possibility that components of a Protection System can be owned by different entities.

The requirements of PRC-004-3 do not map, one-to-one, with the requirements of the legacy standards. The new requirements comingle various reliability attributes of the legacy standards with new reliability objectives, thus a requirement-to-requirement comparison of VRFs is not possible. In developing the new VRFs for the requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-WECC-1, EOP-008-1, PRC-004-2a and of TPL-001-2 influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1, R2 and R3 are assigned a VRF of Medium, while Requirement R4 is assigned a VRF of High.

PRC-004-3 Requirements R1, R2 and R3 are related to identifying Protection System operations, designating Misoperations, investigating Misoperations and developing Corrective Action Plans (CAP) or action plans. The SDT determined that the assignment of a VRF of Medium was consistent with the NERC criterion that states "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..."

PRC-004-3 Requirement R4 relates to implementing and completing CAPs or action plans. The SDT determined that the assignment of a VRF of High was consistent with the NERC criterion that states "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..."

NERC Criteria - 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.

Violation severity levels should be based on the guidelines shown in the table below:

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 Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve 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

Guideline 2a: A violation of a “binary” type requirement must be a “Severe” VSL.

Guideline 2b: 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 and VSL Justifications – PRC-004-3, R1

Proposed VRF	Medium
NERC VRF Discussion	Failure to identify and review each Protection System operation to designate Misoperations, investigate each Misoperation and document the findings 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has Parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has assigned a Medium VRF which is consistent with EOP-008-1 Requirement R8 (which is similar in nature to PRC-004-3 Requirement R1.)
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify and review each Protection System operation to designate Misoperations, investigate each Misoperation and document the findings 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.

VRF and VSL Justifications – PRC-004-3, R1			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.		
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–and~~ 1.32 in more than 120 calendar days but less than or equal to ~~130~~150 calendar days of the operation’s occurrence. OR The responsible entity identified a Protection System operation that operated one of its <u>BES</u> interrupting devices but failed to review the operation in accordance with Requirement R1, Part 1.1. OR The responsible entity completed its review of a Protection System ~~Operation~~ that operated one of its <u>BES</u> interrupting devices in 120	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–and~~ 1.32 in more than ~~130~~150 calendar days but less than or equal to ~~140~~160 calendar days of the operation’s occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–and~~ 1.32 in more than ~~140~~160 calendar days but less than or equal to ~~150~~170 calendar days of the operation’s occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–and~~ 1.32 in more than ~~150~~170 calendar days of the operation’s occurrence. OR The responsible entity failed to identify and review a Protection System operation that operated one of its <u>BES</u> interrupting devices in accordance with Requirement R1, Part 1.1. OR ~~The responsible entity completed its review of a Protection System operation that operated one of its interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to designate the operation as a Misoperation in accordance with Requirement R1, Part 1.2.~~

VRF and VSL Justifications – PRC-004-3, R1

calendar days and determined the operation was a Misoperation and failed to document the findings in accordance with Requirement R1, Part 1.32.

OR

The responsible entity failed to investigate a Misoperation and document the findings in accordance with Requirement R1, Part 1.32.

OR

The ~~responsible~~ entity ~~completed its investigation of~~ that owns the BES interrupting device but does not own the entire Protection System ~~Operation that operated one of its interrupting devices in 120 calendar days and suspected that another entity's could not determine if the operation was correct and failed to notify the other owner(s) of the~~ Protection System component ~~contributed to the Misoperation, and failed to notify (s) and provide any requested investigative information to that entity in accordance with Requirement R1, Part 1.1.~~

VRF and VSL Justifications – PRC-004-3, R1

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-004-3, 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 on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R2

Proposed VRF	Medium
NERC VRF Discussion	Failure to develop a CAP for a Misoperation with an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no Parts so only one VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is similar to EOP-008-1 Requirement R8 which has an approved VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to

VRF and VSL Justifications – PRC-004-3, R2			
	bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC’s criterion for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.		
VRF and VSL Justifications – PRC-004-3, R2			
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 60 calendar days but less than or equal to 70 calendar days following the ~~completion~~ <u>identification</u> of the ~~investigation or receiving notification~~ <u>cause of the Misoperation</u> .	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 70 calendar days but less than or equal to 80 calendar days following the ~~completion~~ <u>identification</u> of the ~~investigation or receiving notification~~ <u>cause of the Misoperation</u> .	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 80 calendar days but less than or equal to 90 calendar days following the ~~completion~~ <u>identification</u> of the ~~investigation or receiving notification~~ <u>cause of the Misoperation</u> .	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, more than 90 calendar days following the ~~completion~~ <u>identification</u> of the ~~investigation or receiving notification~~ <u>cause of the Misoperation</u> . OR The responsible entity failed to develop a CAP or make a declaration in accordance with Requirement R2.

VRF and VSL Justifications – PRC-004-3, R2

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-004-3, 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 on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R3

Proposed VRF	Medium
NERC VRF Discussion	Failure to develop an action plan for a Misoperation without an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no Parts so only one VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is similar to EOP-008-1 Requirement R8 which has an approved VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop an action plan for a Misoperation without an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely

VRF and VSL Justifications – PRC-004-3, R3			
	to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC’s criterion for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.		
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 180 calendar days but less than or equal to <u>190210</u> calendar days following the associated <u>BES</u> interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than <u>190210</u> calendar days but less than or equal to <u>200220</u> calendar days following the associated <u>BES</u> interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than <u>200220</u> calendar days but less than or equal to <u>210230</u> calendar days following the <u>completion of the investigation associated BES interrupting device operation.</u>	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, more than <u>210230</u> calendar days following the <u>completion of the investigation associated BES interrupting device operation.</u> OR The responsible entity failed to develop, <u>implement, and document</u> an action plan, or a declaration in accordance with Requirement R3.

VRF and VSL Justifications – PRC-004-3, R3

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-004-3, 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 on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R4

Proposed VRF	High
NERC VRF Discussion	Failure to implement a CAP or action plan to address an identified Misoperation could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. This is a planning requirement that meets the NERC criterion for a High VRF.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has <u>no</u> Parts ~~that all support the reliability objective~~ so only one VRF was assigned; ~~therefore no conflict(s) exist.~~
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is consistent with PRC-004-2a, Requirements R1 and R2, PRC-004-WECC-1 Requirement R2.1, and TPL-001-2 Requirement R2 Part 2.7 which have approved VRFs of High.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a CAP or action plan to address an identified Misoperation could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. This is a planning requirement that meets the NERC criterion for a High VRF.

VRF and VSL Justifications – PRC-004-3, R4			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does contain obligations that are administrative in nature but they support the high risk reliability objective; the assigned VRF of High is appropriate for the requirement.		
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity ~~maintained records or~~ <u>failed to revise</u> a CAP or action plan ~~but the records were incomplete as~~ <u>needed in accordance with Requirement R4.</u>	<u>N/A</u>	<u>N/A</u>	The responsible entity failed to implement a CAP or action plan. OR ~~The responsible entity failed to maintain records of a CAP or action plan in accordance with Requirement R4.~~

VRF and VSL Justifications – PRC-004-3, R4

NERC VSL Guidelines	Meets NERC's VSL Guidelines— ~~There is an incremental aspect to~~ <u>The VSLs cover aspects of the VSLs for incomplete documentation and a binary aspect for failure to implement requirement that are not equal in importance.</u>
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the previous severity level and does not lower the current level of compliance for the similar Requirement.
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 proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-004-3, R4	
Corresponding 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 on a single violation and not cumulative violations.

Standards Announcement

Project 2007-09 Generator Verification

PRC-024-1

Formal Comment Period: January 25, 2013 – February 25, 2013

Upcoming:

Successive Ballot and Non-Binding Poll: February 15, 2013 – February 25, 2013

[Now Available](#)

A 30-day formal comment period is open for **PRC-024-1** – Generator Performance During Frequency and Voltage Excursions through **8 p.m. Eastern on Monday, February 25, 2013**.

A successive ballot of **PRC-024-1** and non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Friday, February 15, 2013 through 8 p.m. Eastern on Monday, February 25, 2013**.

The remaining four standards (MOD-025-2, MOD-026-1, MOD-027-1 and PRC-019-1) in this project passed the recirculation ballot on December 21, 2012 and will be presented to the NERC Board of Trustees for adoption at its February meeting.

Instructions for Commenting

A formal comment period for **PRC-024-1** is open through **8 p.m. Eastern on Monday, February 25, 2013**. Please use this [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the [project page](#).

Next Steps

A successive ballot of PRC-024-1 and non-binding poll of the associated VRFs and VSLs will be conducted from February 15, 2013 through February 25, 2013.

Background

The purpose of Project 2007-09 - Generator Verification is to ensure that: 1) generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator-protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities); and 2) that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 - Generator Verification - based part of its work on two existing NERC Board-approved standards, MOD-024-1 — Verification of Generator Gross and Net Real Power Capability and MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability. The drafting team moved the Requirements of MOD-024-1 into MOD-025-2, and recommends retiring MOD-024-1 and incorporated industry comments to make improvements to the standards.

The drafting team has also based its work on four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007:

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

Additional information is available on the [project page](#).

Standards Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Monica Benson,
Standards Development Administrator, at monica.benson@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
3353 Peachtree Rd. NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Unofficial Comment Form

Project 2007-09 Generator Verification PRC-024-1 Generator Frequency and Voltage Protective Relay Settings

Instructions

Please **DO NOT** use this form for commenting. Please use the [electronic comment](#) form to submit comments on the proposed revisions to PRC-024-1. Comments must be submitted by 8 p.m. ET **Monday, February 25, 2013**. If you have questions please contact Stephen Crutchfield at stephen.crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information

The Generator Verification Standard Drafting Team posted PRC-024-1 - Generator Frequency and Voltage Protective Relay Settings, from December 12, 2012 through January 11, 2013 for a 30-day concurrent comment/successive ballot period. The GVSDT received valuable feedback from stakeholders regarding improvements to the standard. Many of the suggested edits were incorporated into the revised standard.

The vast majority of stakeholders agreed with the removal of R5 from the standard. Several stakeholders suggested that there were issues with R4. These commenters pointed out that the requirement was ambiguous and provided no discernible reliability benefit while subjecting entities to potential compliance violations for making optimistic estimations. Stakeholders believe that the use of language such as “sound engineering judgment” is subject to interpretation and vague. Based on these comments, the GVSDT removed R4 from the standard. PRC-024-1 is now a relay setting standard.

Minority issue: Under FERC Order 661A, the wind industry is currently subject to more stringent voltage and frequency ride-through standards than other generation types, and keeping PRC-024 as a generator performance standard would have helped to level the playing field in this regard. The proposed draft of PRC-024 does not accomplish this. The GVSDT points out that the requirements contained in FERC Order 661A are enforced through Generator Interconnection Agreements and not NERC Standards.

A large majority of stakeholders agreed with the change made to Attachment 1. Some stakeholders questioned the potential impact this change might make due to the elimination of the margin between the allowable UFLS overshoot and the generator overfrequency trip setpoints. The GVSDT pointed out that setting overfrequency tripping at this point would be allowed under the previous curve as a technically-based exemption under Requirement R3 and the change made removes a conflict with internationally-recognized technical standards.

Most stakeholders agreed with the revisions to the voltage ride-through curves in Attachment 2. Several stakeholders had concerns with the low voltage ride-through criteria being lowered to 85% for the 3-4 second interval. Stakeholders pointed out that transmission systems are designed to operate between 90% to 110% and not down to 85% and as such we do not expect generators to ride through voltages as low as 85% for an extended period of time. The GVSDT agrees with these comments and has revised the voltage ride-through chart 85% voltage level to the original 90%. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator). The majority of commentators agreed with the removal of loadability relays from PRC-024. The majority of comments expressed agreement with the removal of loadability relays from PRC-024. One commentator recommended that the Generator Relay Loadability drafting team vet the removal of these relay types from Footnote 1. The GVSDT had previous discussions with that drafting team and they concurred with the revision to PRC-024.

Stakeholders provided valuable input regarding suggested improvements to language within the standard. Based on these comments, the following improvements were made to the draft standard:

- Removed R4 from the standards because of ambiguous language and dubious reliability benefit.
- Revised the title of the standard to “Generator Frequency and Voltage Protective Relay Settings” and the Purpose Statement to “Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
- Revised “generating unit(s)” to “applicable generating unit(s)” to reflect that the standard only applies to units that meet the registry criteria.
- Revised language of R1 to match that of R2.
- Added “regulatory or” language regarding limitations to reflect that NERC, environmental or regulatory requirements may cause a limitation in generator performance.
- Revised R2 so that the sentences were shorter and easier to read.
- Removed the last bullet from R3 and added a new bullet referencing frequency impacts on turbines as follows: “Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.”
- Revised R5 (now R4) to indicate that the trip settings to be provided are only those “associated with Requirements R1 and R2” and not all relays.
- Revised the measures based on requirement revisions.
- Updated the VSLs for R3 and R4 to allow 30 day increments between levels rather than the original 10 days. This comports with other standards developed under this project.
- Updated the table in Attachment 2 (this was missed in the previous revision).

- Made clarifying revisions to “Voltage Ride-Through Curve Clarifications” on the last page of the standard.
- Clarified Footnote 3 to: “Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.”

Questions

1. The GVSDT has removed Requirement R4 from the standard. Stakeholders suggested that the requirement was ambiguous and provided no discernible reliability benefit while subjecting entities to potential compliance violations for making optimistic estimations. Stakeholders believe that the use of language such as “sound engineering judgment” is subject to interpretation and vague. Do you agree with this revision? If not, please explain in the comment area below.

☒ Yes

☐ No

Comments:

2. Do you have any other comment, not expressed in question above, for the GVSDT?

Comments:

Standard Development Roadmap

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

Development Steps Completed:

1. SAR posted for comment (April 20–May 21, 2007).
2. Revised SAR and response to comments posted.
3. Revised SAR and response to comments approved by SC (June 14, 2007).
4. SDT appointed on (August 18, 2007).
5. Initial draft of PRC-024-1 was posted for a 45 day formal comment period (February 17 – April 2, 2009).
6. Draft 2 of PRC-024-1 was posted for a 45 day concurrent comment and ballot period from June 15 – August 1, 2011.
7. Draft 3 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from February 29 – March 29, 2012.
8. Draft 4 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from September 28 – October 31, 2012.
- 8.9. Draft 5 of PRC-024-1 was posted for a 30 day concurrent comment and successive ballot period from December 12, 2012 – January 11, 2013.

Proposed Action Plan and Description of Current Draft:

This is the sixth~~fifth~~ draft of the standard and includes Time Horizons, Data Retention, Violation Risk Factors, and Violation Severity Levels. This sixth~~fifth~~ posting is for a 30-day comment and successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop responses to comments and develop <u>sixth</u> ~~fifth~~ version draft standard.	<u>December 2012</u> <u>January 2013</u>
2. Post response to comments and conduct successive ballot.	<u>February 2013</u> ~~December 2012~~

Draft 6~~5~~

Date: January 17, 2013~~December 6, 2012~~

Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings
~~Generator Performance During Frequency and Voltage Excursions~~

3. Develop responses to ballot comments.	<u>March</u> ~~January~~ 2013
4. Post responses to comments and conduct recirculation ballot.	<u>April</u> ~~January~~ 2013
5. BOT adoption.	<u>May</u> ~~February~~ 2013
6. File with regulatory authorities.	<u>June</u> ~~March~~ 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings ~~Performance During Frequency and Voltage Excursions~~
2. **Number:** PRC-024-1
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions, ~~and ensure expected generating unit performance during frequency and voltage excursions is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.~~
4. **Applicability:**
 - 4.1. Generator Owner
5. **Effective Date:**
 - 5.1. In those jurisdictions where regulatory approval is required:
 - 5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5.~~
 - 5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5.~~
 - 5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5.~~
 - 5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5.~~
 - 5.2. In those jurisdictions where regulatory approval is not required:

- 5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.
- 5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.
- 5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.
- 5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.

B. Requirements

- R1.** Each Generator Owner that has generator frequency protective relaying¹ activated to trip its applicable generating unit(s) shall set ~~such its~~ protective relaying ~~such~~ that the frequency protective relaying does not ~~operate to~~ trip the applicable generating unit(s) within the “no trip zone” of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.
 - Generating unit(s) may trip if clearing a system fault necessitates disconnecting ~~(a) the~~ generating unit(s).
 - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R2.** Each Generator Owner that has generator voltage protective relaying¹ activated to trip its applicable generating unit(s) shall set its protective relaying such that the voltage protective relaying does not trip as a result of a voltage excursion (at the point of interconnection²) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set or its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner’s study. ~~if the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2 Requirement R2 is~~ subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
 - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).

¹ Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

² For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings
Generator Performance During Frequency and Voltage Excursions

- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
 - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R3.** Each Generator Owner shall document each known regulatory or equipment limitation³ that prevents an applicable generating unit from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer’s advisory. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*:
- 3.1.** The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its ~~Reliability Coordinator~~, Planning Coordinator, ~~Transmission Operator~~ and Transmission Planner within 30 calendar days of any of the following:
- Identification of a regulatory or equipment limitation.
 - Repair of the equipment causing the limitation that removes the limitation.
 - Replacement of the equipment causing the limitation with equipment that removes the limitation.
 - Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.
 - Modification or upgrade of the equipment causing the limitation that results in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard).
- ~~**R4.** Within 60 calendar days of receipt of a written request from a Planning Coordinator or Transmission Planner, each Generator Owner shall provide an estimate of the time duration which the generating unit(s) will remain connected (including the performance of the auxiliary systems) if the unit(s) were to experience a frequency or voltage excursion. The voltage or frequency profile at the point of interconnection is provided by a Planning Coordinator or Transmission Planner that models the associated generating unit(s) and which has requested the time duration estimate.~~

³ Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

~~If the Generator Owner expects the generating unit(s) will remain connected for the duration of the profile of the excursion provided, the estimate should indicate the generating unit(s) is not expected to trip. The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment. Detailed generating unit(s) performance studies are not required to develop the estimate. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]~~

R5.R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner ~~(that models the associated unit)~~, within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings unless ~~otherwise~~ directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required.
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

C. Measures

- M1.** Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets, or other documentation.
- M2.** Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 ~~evidence~~ such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, ~~or~~ dynamic simulation studies or other documentation.
- M3.** Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3 ~~that are caused by generator frequency and voltage protective relays~~) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advisory.
- ~~**M4.** Each Generator Owner shall have evidence that an estimate of the time duration of its existing generating unit(s) as a result of a frequency excursion or voltage excursion has been communicated in accordance with Requirement R4, such as a copy of the estimate of time duration report and correspondence, such as dated e-mails, or other documentation and copies of any requests it has received for that information.~~
- M5.M4.** Each Generator Owner shall have evidence that it communicated generator protective relay settings ~~to a requesting entity within 60 calendar days of a request or change in setting(s)~~ in accordance with Requirement R4~~5~~, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data 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 Generator Owner shall retain evidence of compliance with Requirement R1 through R45, Measures M1 through M45; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved 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 Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit has no documented and communicated <u>regulatory or</u> equipment limitation per Requirement R3 and failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit has no documented and communicated <u>regulatory or</u> equipment limitation per Requirement R3 and failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from	The Generator Owner documented the known non-protection system equipment limitation that prevented it from	The Generator Owner documented the known non-protection system equipment limitation that prevented it from	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from

Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings ~~Generator Performance During Frequency and Voltage Excursions~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its ~~Reliability Coordinator~~ , Planning Coordinator, ~~Transmission Operator~~ and Transmission Planner more than 30 calendar days but less than or equal to ~~40~~ <u>60</u> calendar days of identifying the limitation.	meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its ~~Reliability Coordinator~~ , Planning Coordinator, ~~Transmission Operator~~ and Transmission Planner more than ~~640~~ calendar days but less than or equal to ~~950~~ calendar days of identifying the limitation.	meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its ~~Reliability Coordinator~~ , Planning Coordinator, ~~Transmission Operator~~ and Transmission Planner more than ~~950~~ calendar days but less than or equal to ~~1260~~ calendar days of identifying the limitation.	meeting the criteria in Requirement R1 or R2. OR The Generator Owner failed to communicate the documented limitation to its ~~Reliability Coordinator~~ , Planning Coordinator, ~~Transmission Operator~~ and Transmission Planner within ~~1260~~ calendar days of identifying the limitation.
~~R4~~	~~The Generator Owner provided an estimate of a unit's performance more than 60 calendar days but less than or equal to 70 calendar days of a written request.~~	~~The Generator Owner provided an estimate of a unit's performance more than 70 calendar days but less than or equal to 80 calendar days of a written request.~~	~~The Generator Owner provided an estimate of a unit's performance more than 80 calendar days but less than or equal to 90 calendar days of a written request.~~	~~The Generator Owner failed to provide an estimate of a unit's performance within 90 calendar days of a written request.~~ :
~~R45~~	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to ~~790~~ calendar days of any change to those trip settings.	The Generator Owner provided its generator protection trip settings more than ~~970~~ calendar days but less than or equal to ~~12080~~ calendar days of any change to those trip settings.	The Generator Owner provided its generator protection trip settings more than ~~1280~~ calendar days but less than or equal to ~~15090~~ calendar days of any change to those trip settings.	The Generator Owner failed to provide its generator protection trip settings within ~~15090~~ calendar days of any change to those trip settings.

Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings ~~Generator Performance During Frequency and Voltage Excursions~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to <u>970</u> calendar days of a written request.	OR The Generator Owner provided trip settings more than <u>970</u> calendar days but less than or equal to <u>1280</u> calendar days of a written request.	OR The Generator Owner provided trip settings more than <u>1280</u> calendar days but less than or equal to <u>1590</u> calendar days of a written request.	OR The Generator Owner failed to provide trip settings within <u>1590</u> calendar days of a written request for the data.

Draft 65

Date: January 17, 2013 ~~December 6, 2012~~

E. Regional Variances

None

F. Associated Documents

None

Version History

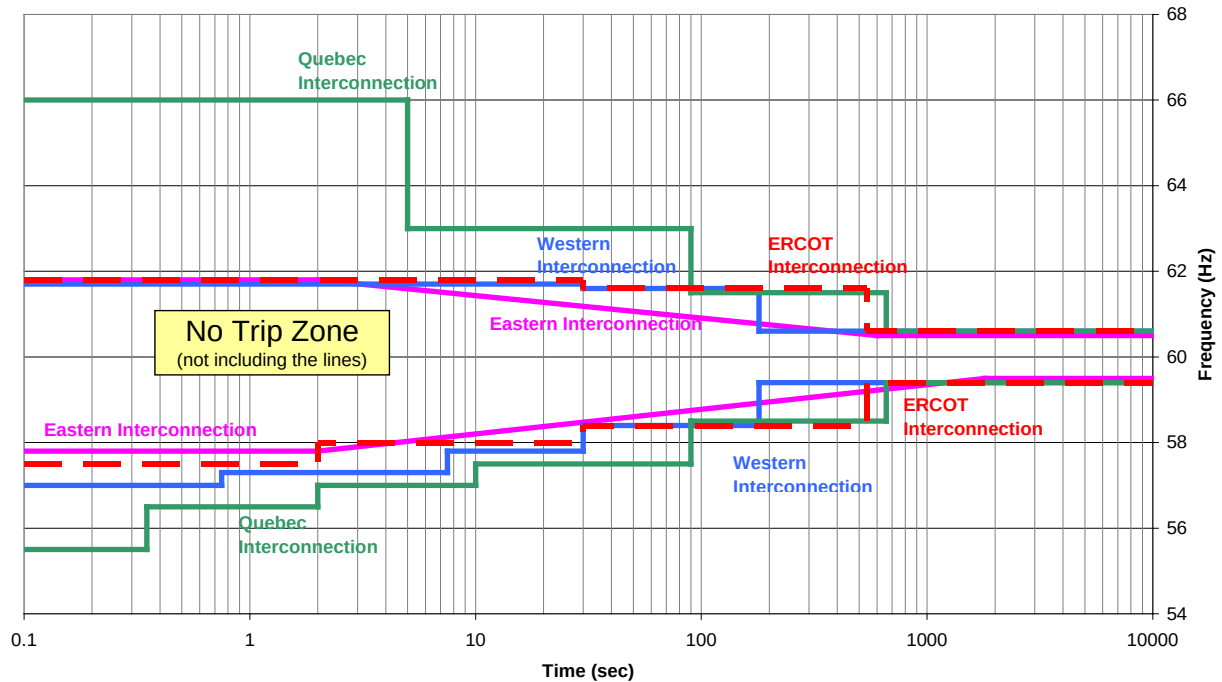
Version	Date	Action	Change Tracking

G. References

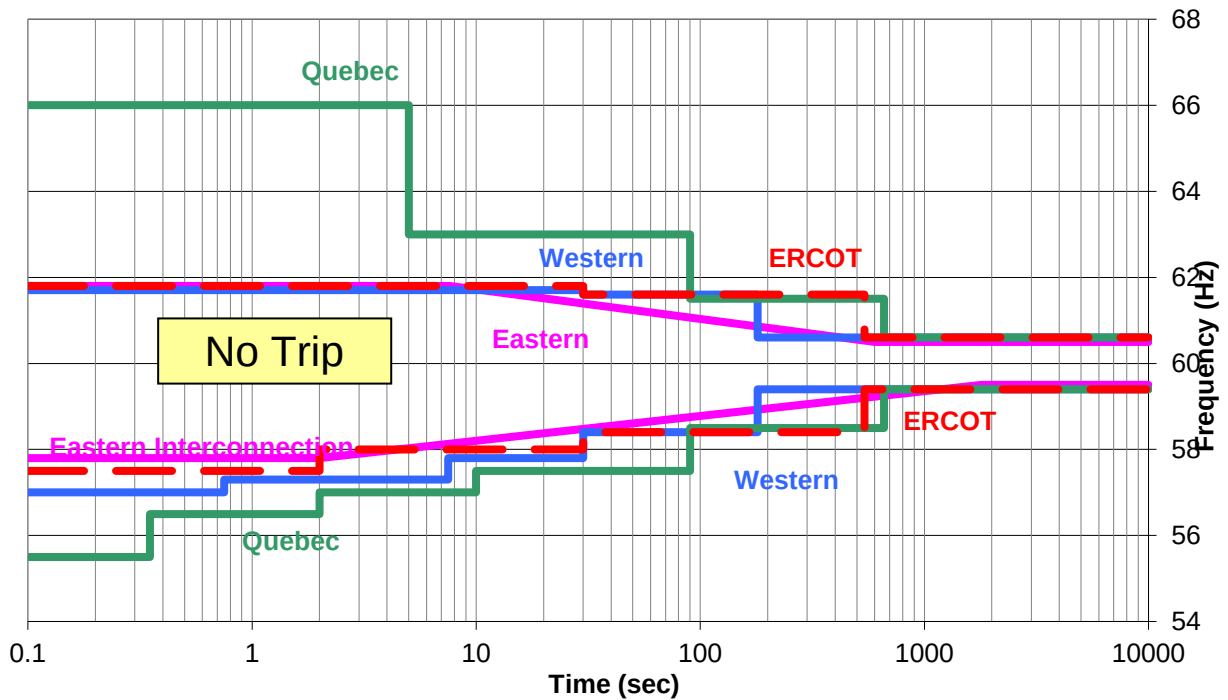
1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935118-0.602-1.457139055 \cdot f)}$	≤59.5	$10^{(1.7373 \cdot f - 100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

Quebec Interconnection

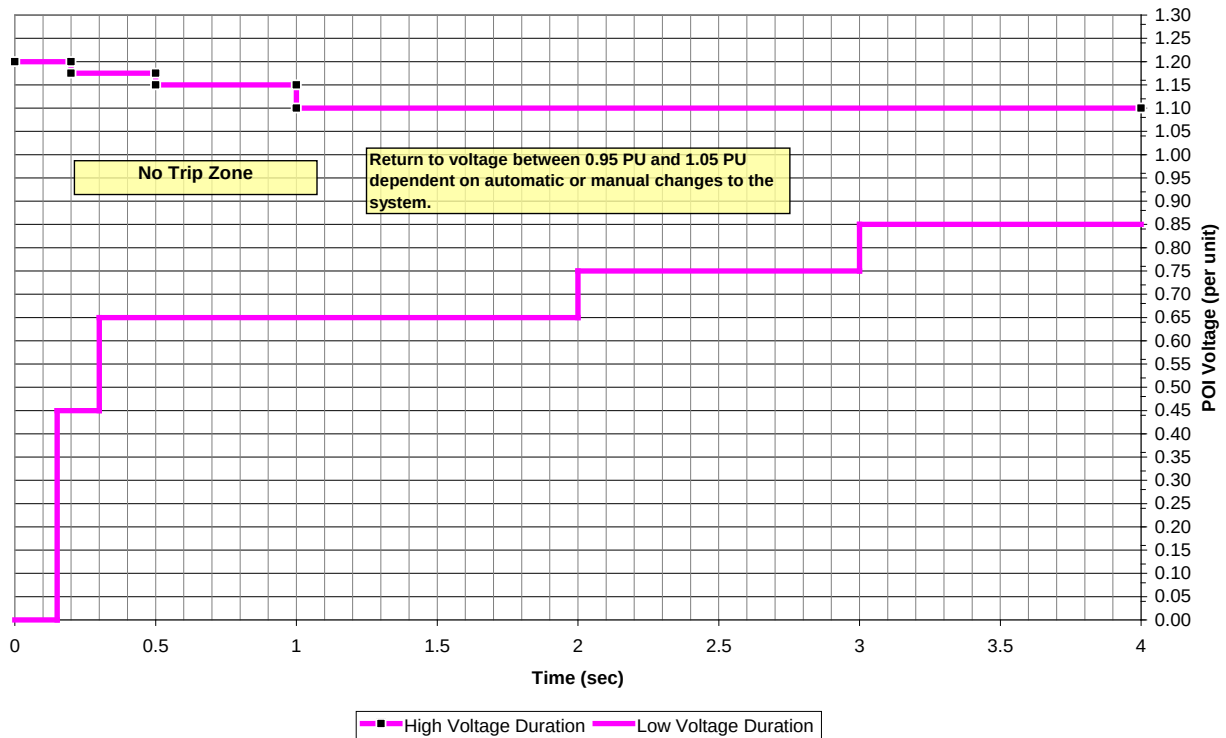
High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

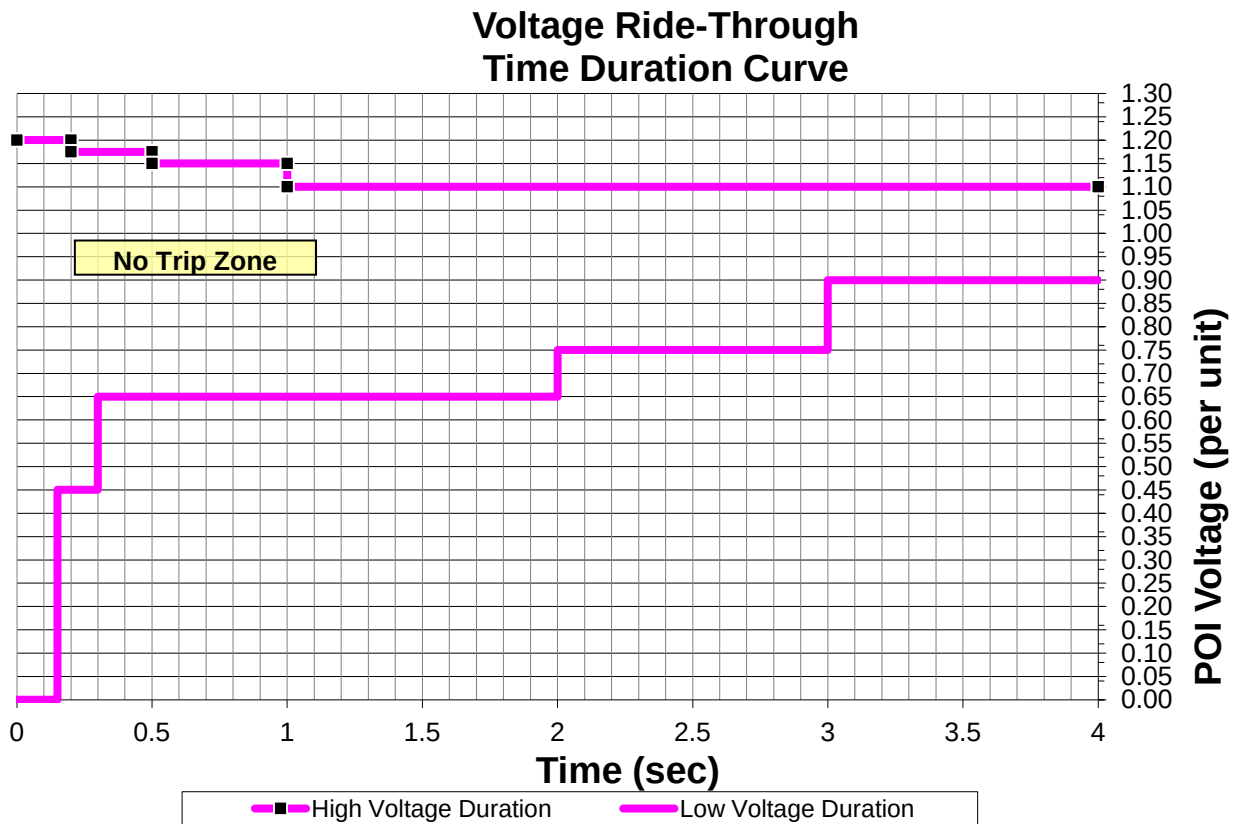
ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2

Voltage Ride-Through Time Duration Curve





Ride Through Duration Curve Data Points:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥ 1.200	Instantaneous trip	~~0.00~~ ≤ 0.45	0.15
≥ 1.175	0.20	~~0.45~~ ≤ 0.65	0.30
≥ 1.15	0.50	~~0.65~~ ≤ 0.75	2.00
≥ 1.10	1.00	~~0.75~~ ≤ 0.90	3.00
> 1.05	600	~~0.90~~	600
≤ 1.05	Continuous operation	≥ 0.95	Continuous operation

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may ~~A~~adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz. normal.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
 - a. All of the units connected to the same transformer are online and operating.
 - b. All of the units are at full nameplate real-power output.
 - c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals).
 - d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAR compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Project 2007-09 Generator Verification Consideration of Issues and Directives

Project 2007-09 Generator Verification — PRC-024-1		
Issue or Directive	Source	Consideration of Issue or Directive
Paragraph 1787 states "... the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. "	FERC Order 693; Paragraph 1787	The GVSDT believes that Requirement R2 and the voltage ride through curves in PRC-024 Attachment 2 accomplish this. While the curves were developed based on three phase normally cleared faults located at a generating plant substation (the most severe condition for generating equipment), the curves cover voltages depressed as low as 0.65 per unit for two seconds, which the GVSDT feels will cover the Category B and C events of concern to the Commission. Requirement R3 allows an exemption from portions of the ride through curves in PRC-024 Attachments 1 and 2 for documented regulatory or technical reasons, but directs those generators to communicate that limitation to the PC and TP so its performance can be modeled correctly. ~~In addition, Requirement R4 allows the PC or TP to request an estimate of performance (ride through duration) from the GO for a defined excursion. The estimate would cover process upsets to the generating equipment that might result in a delayed trip, even if the generator protection itself did not cause a trip.~~

Project 2007-09 Generator Verification — PRC-024-1		
Issue or Directive	Source	Consideration of Issue or Directive
Paragraph 1787 also states "... the Commission agrees that NRC requirements should be used when implementing the Reliability Standards."	FERC Order 693; Paragraph 1787	The GVSDT believes that Requirement R3 allows NRC requirements to supersede portions of the voltage and frequency ride through criteria in PRC-024-1. This Requirement allows generators an exemption from portions of the ride through curves for documented regulatory ~~technical~~ limitations. The GVSDT believes that NRC requirements qualify as regulatory ~~technical~~ limitations for the purposes of this standard.

Implementation Plan

Project 2007-09 Generator Verification

Implementation Plan for PRC-024-1, Generator Frequency and Voltage Protective Relay Settings Performance During Frequency and Voltage Excursions

Approvals Required

PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings Performance During Frequency and Voltage Excursions.

According to its Implementation Plan, PRC-006-1, Requirement R4 (see project 2007-01, Underfrequency Load Shedding) does not become effective until PRC-024-1 becomes effective. Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.

Prerequisite Approvals

None

Revisions to Glossary Terms

None

Applicable Entities

Generator Owner

Conforming Changes to Other Standards

None

Effective Dates

In those jurisdictions where regulatory approval is required:

- o By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.

- o By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.
- o By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.
- o By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.

In those jurisdictions where regulatory approval is not required:

- o By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.
- o By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.
- o By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.
- o By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its applicable Facilities are fully compliant with Requirements R1, R2, R3, and R4, ~~and R5~~.

Retirements

None

Justification of Phasing

Requirements R1, R2, R3, and R4, ~~and R5~~ involve evaluation of existing protection system settings and equipment capabilities. Typically, generator protection system setting changes are made during scheduled generator outages. The Implementation Plan allows a five-year window for these changes to be made which corresponds to typical outage cycles. Generating units that have outage cycles that extend longer than five years are not typically base loaded and offer opportunities to effect protection system settings changes during economic shut down periods.

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-09 Generator Verification

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings~~Generator Performance During Frequency and Voltage Excursions~~.

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 Generator Verification 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 Requirements 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 PRC-024-1:

There are ~~four~~ ~~five~~ requirements in PRC-024-1. Two of the Requirements (R1, and R2) were assigned a "Medium" VRF and the remaining ~~two~~ ~~three~~ requirements were assigned a "Lower" VRF.

VRF for PRC-024-1, Requirement R1:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R1 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R2 ~~and R5, both of~~ which were assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a "Medium" VRF.

- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to ensure a proper frequency “no-trip” operating window is a requirement in the planning time frame that, if violated, 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. ~~–~~ Therefore the assigned “Medium” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R1 reliability objective is to ensure a proper frequency “no-trip” operating window. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The “Medium” VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirement R2:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R2 contains Parts specifying conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally. Requirement obligations include actions similar in scope to actions specified in Requirement R1 ~~and R5, both of~~ which were assigned a “Medium” VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. This requirement is assigned a “Medium” VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to ensure proper voltage “no-trip” criteria is a requirement in the planning time frame that, if violated, 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. Therefore the assigned “Medium” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R2 reliability objective is to ensure proper voltage “no-trip” criteria. Requirement Parts are lower risk condition elements that establish main requirement criteria for completeness. The “Medium” VRF assigned is based on the reliability objective specified.

VRF for PRC-024-1, Requirements R3:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R3 contains Parts specifying response expectation and limitation reset conditions for satisfying the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with PRC-006-0 Requirement R1 which specifies documentation requirements. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a “Lower” VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to document limitations preventing compliance is a requirement that is administrative in nature for the 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. Therefore the assigned “Lower” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R3 reliability objective is to document limitations preventing compliance. Requirement Parts and obligations are lower risk elements that ensure main requirement completeness which are administrative in nature consisting of response submission and limitation reset condition requirements. The “Lower” VRF assigned is based on the reliability objective specified.

~~VRF for PRC-024-1, Requirement R4:~~

- ~~• FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R4 contains Parts that are procedural in nature defining criteria associated with the main requirement. The VRFs are only applied at the Requirement level and each Requirement Part is treated equally.~~
- ~~• FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement requires an estimate of performance and is somewhat similar in concept with both PRC-009-0 Requirement R1 and PRC-014-0 Requirement R2, both of which reference protection analysis or assessment for determining adequacy. In addition, as is generally the case with reliability standard VRF definitions for analysis & assessment planning type requirements, this requirement is assigned a “Lower” VRF.~~
- ~~• FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to estimate performance during a frequency or voltage excursion is a requirement that is administrative in nature for the 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. Therefore the assigned “Lower” VRF is appropriate.~~

- ~~FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R4 reliability objective is to estimate performance during a frequency or voltage excursion. Requirement Parts and obligations are lower risk procedure based criteria for the main requirement. The “Lower” VRF assigned is based on the reliability objective specified.~~

VRF for PRC-024-1, Requirement R~~45~~:

- FERC Guideline 2 — Consistency within a Reliability Standard exists. Requirement R~~45~~ does not contain Parts. Requirement obligations specify the type of response and response time frame to be observed.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept with both PRC-007-0 Requirement R3 and PRC-010-0 Requirement R2, both of which require providing information within a specified time frame on request. In addition, as is generally the case with reliability standard VRF definitions for documentation and administrative requirements, this requirement is assigned a “Lower” VRF.
- FERC Guideline 4 — Consistency with NERC’s Definition of the VRF Level selected exists. Failure to provide setting and limitation information as requested is a requirement that is administrative in nature for the 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. Therefore the assigned “Lower” VRF is appropriate.
- FERC Guideline 5 — Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement R~~45~~ reliability objective is to provide setting and limitation information as requested. Requirement obligations are lower risk condition elements administrative in nature for ensuring the main requirement is satisfied in a timely manner. The “Lower” VRF assigned is based on the reliability objective specified.

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 PRC-024-1 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 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.

VSLs for PRC-024-1 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 by incorporating binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 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 binary VSL elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's are a combination of binary elements and are categorized as severe. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action per the conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 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 increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner including response obligation and reset conditions specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 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 by incorporating increments for tardiness.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's reflect increments for tardiness. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on binary performance, and both completeness and timeliness of the actions and obligations specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner per the procedure criteria specified by listed parts. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

VSLs for PRC-024-1 Requirement **R45**:

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
R46 .	The NERC VSL guidelines are satisfied by incorporating increments for tardiness elements.	This is a new Requirement and does not have a prior level of compliance.	Proposed VSL's incorporate the increments for tardiness methodology. Proposed VSL language does not include ambiguous terms and ensure uniformity and consistency in the determination of penalties based on timeliness of the action specified.	Proposed VSL's do not expand on what is required in the requirement. The VSL's assigned only consider performing required action in a timely manner. Proposed VSL's are consistent with the requirement.	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Standards Announcement

Project 2010-13.2 – Phase 2 of Relay Loadability: Generation

Ballot Pools Forming: January 25 – February 25, 2013

Formal Comment Period: January 25 – March 11, 2013

Additional Documents Posted for Comment:

Cost Effectiveness Comment Period: January 25 – March 11, 2013

Supplemental SAR Informal Comment Period: January 25 – March 11, 2013

RSAW Posted for Industry Comments: January 25 – March 11, 2013

Upcoming:

Initial Ballot and Non-Binding Poll: March 1 – March 11, 2013

Now Available

A formal comment period for **PRC-025-1 – Generator Relay Loadability** is open through **8 p.m. Eastern on Monday, March 11, 2013** and ballot pools are forming through **8 a.m. Monday, February 25, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

An initial ballot of **PRC-025-1** and non-binding poll of the associated VRFs and VSLs will also be conducted during this period, beginning on **Friday, March 1, 2013** through **8 p.m. Eastern on Monday, March 11, 2013**.

Alongside the comment period, three additional documents will be posted for industry comment: a draft cost effective analysis (CEA), a supplemental SAR, and a draft Reliability Standard Audit Worksheet (RSAW).

In response to concerns expressed by stakeholders and regulators, NERC has developed a Cost Effective Analysis Process (CEAP) to introduce the concept of cost consideration and effectiveness into the development of new and revised standards. As part of the pilot of the CEAP, NERC is proposing to conduct a CEA to provide information about cost impacts of draft Reliability Standards and their relative effectiveness, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of the standard. The revisions under Project 2010-13.2 have been deemed to be required to meet an adequate level of reliability, and therefore, “Phase I” of the CEAP (a cost impact assessment) is unnecessary. A pilot of “Phase II” of the CEAP, the CEA, is posted for industry comment through **8 p.m. Eastern on Monday, March 11, 2013**. More information about the CEAP is available on [the project page](#).

A supplemental SAR has also been developed to revise PRC-023-2 and is posted for an informal comment period.

Finally, PRC-025-1 was drafted in conjunction with the development of its RSAW, which is posted for an informal comment period.

Instructions for Joining Ballot Pool(s)

Ballots pools are being formed for the standard and non-binding poll for PRC-025-1. Registered Ballot Body members must join both ballot pools to be eligible to vote in the balloting of PRC-025-1 and to submit an opinion for the non-binding poll of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: [Join Ballot Pool](#).

During the pre-ballot window, members of the ballot pool may communicate with one another by using the “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list servers for the ballot pools are:

Initial ballot: bp-2010-13.2_PRC-025-1_in@nerc.com

Non-binding poll: bp-2010-13.2_NB_PRC-025_in@nerc.com

Instructions for Commenting

A formal comment period is open for PRC-025-1 through **8 p.m. Eastern on Monday, March 11, 2013**. The supplemental SAR to revise PRC-023-2 and CEA have also been posted for industry comment. Please use the links below to the electronic comment forms to submit comments:

[PRC-025-1
Supplemental SAR
Cost Effective Analysis](#)

If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the [project page](#).

A comment period on the draft RSAW is open through **8 p.m. Eastern on Monday, March 11, 2013**. The draft RSAW is posted on the NERC Compliance Reliability Standard Audit Worksheet page. Please submit comments on the draft RSAW by using the RSAW feedback form on the [project page](#) and sending to: RSAWfeedback@nerc.net.

Next Steps

An initial ballot will be conducted **March 1, 2013** through 8 p.m. **Monday, March 11, 2013**.

Background

The March 18, 2010 FERC Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In this Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, developing a new Reliability Standard to address generator

protective relay loadability, and developing another Reliability Standard to address the operation of protective relays due to power swings. This project's SAR addresses these directives and establishes a three-phase approach to standard development.

Phase I was focused on making the specific modifications to PRC-023-1 and was completed in the approved PRC-023-2 Reliability Standard, which became mandatory on July 1, 2012. This project, Phase II, is focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. This Reliability Standard establishes requirements for the Generator Operator functional entity to set protective relays at a level such that generating units do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service. Phase III, which will follow this project, will focus on developing requirements that address protective relay operations due to stable power swings.

Additional information can be found on the [project page](#).

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com



Reliability Standard Audit Worksheet¹

PRC-025-1 – Generator Relay Loadability

This section must be completed by the Compliance Enforcement Authority

Registered Entity:

NCR Number:

Applicable Function(s): GO

Applicable CAN(s): None

Applicable Bulletin(s): None

Compliance Assessment Date:

Compliance Monitoring Method:

Names of Auditors:

¹ NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website at <http://www.nerc.com/page.php?cid=2|20>. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

DRAFT NERC Reliability Standard Audit Worksheet

Compliance Enforcement Authority: _____

Registered Entity: _____

NCR Number: _____

Compliance Assessment Date: _____

RSAW Version: RSAW_PRC-025-1_2013_v1

DRAFT NERC Reliability Standard Audit Worksheet

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response **(Required)**:

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Generator Owner shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.
[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]

Question: [Author to insert Question here if applicable, otherwise delete Question and Registered Entity Response below]

Registered Entity Response to Question **(Required)**:

Registered Entity Compliance Response **(Required)**:

Describe, in narrative form, how you meet compliance with this Requirement.

Registered Entity Evidence **(Required)**:

Provide the following for all evidence submitted (Insert additional rows if necessary): File Name, File Extension, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description

Audit Team Evidence Reviewed **(This section must be completed by the Compliance Enforcement Authority)**:

DRAFT NERC Reliability Standard Audit Worksheet

Compliance Enforcement Authority: _____

Registered Entity: _____

NCR Number: _____

Compliance Assessment Date: _____

RSAW Version: RSAW_PRC-025-1_2013_v1

DRAFT NERC Reliability Standard Audit Worksheet

Compliance Assessment Approach Specific to PRC-025-1, R1

This section must be completed by the Compliance Enforcement Authority

Review the evidence to verify the Registered Entity has:

	Verify that the Generator Owner has evidence for each load-responsive protective relay, applied on its Facilities, within the sample set or full population, of data being audited.
	Verify that the Generator Owner's evidence, within the sample set or full population, includes the following attributes: 1. Dated, within the implementation period: a. Pickup Setting Criteria values were verified before the end of the 48-month implementation in order to determine whether existing relays are capable of complying with the standard or identified for replacement. 2. Used appropriate elements from <i>PRC-025-1 – Attachment 1: Relay Settings</i>, and that the evidence reasonably identifies the criteria in Table 1 (e.g., application, relay type, option, voltage, Real Power, Reactive Power, and Pick up setting).
	Verify that the Generator Owner applied the setting consistent with the criteria according to <i>PRC-025-1 – Attachment 1: Relay Settings</i> . Identify that evidence contains the following elements: 1. Dated, within the implementation period: a. For relays not identified for replacement, the setting was applied before the end of the 48-month implementation period, or b. For relays identified for replacement, the setting was applied before the end the 72-month implementation period. 2. Confirm the setting specified in the evidence corresponds with the entity's documentation it applied the setting.
Note to Auditor: None	

Auditor Notes:

Compliance Finding Summary [\[Author to update table based on number of Requirements in the standard\]](#)

This section must be completed by the Compliance Enforcement Authority

Req.	NF	PV	OEA	NA	Statement
1					

DRAFT NERC Reliability Standard Audit Worksheet

Revision History

REVISION DATE	REVISION DETAILS	REVISED BY
1/23/2013	New draft RSAW	Standards Drafting Team

From: [Guy V. Zito](#)
To: [rsc](#)
Subject: FW: NERC Standards Announcement | Project 2010-13.2 Phase 2 of Relay Loadability: Generation | Comment Period Now Open through Monday, March 11, 2013
Date: Monday, January 28, 2013 9:19:31 AM

RSC,

FYI, the below announcement contains the first CEAP posting, specifically the Phase 2 Cost Effectiveness Analysis portion. I will be reaching out to the North American Generator Forum to notify them of them as this proposed standard is applicable to the generators.

Thanks,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: NERC Standards Announcements (Do Not Reply) [mailto:NERC-StandardsAnnouncements-DoNotReply@nerc.net]

Sent: Friday, January 25, 2013 1:16 PM

To: Wendy Muller

Subject: NERC Standards Announcement | Project 2010-13.2 Phase 2 of Relay Loadability: Generation | Comment Period Now Open through Monday, March 11, 2013

Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation

Ballot Pools Forming: January 25 – February 25, 2013
Formal Comment Period: January 25 – March 11, 2013

Additional Documents Posted for Comment:

Cost Effectiveness Comment Period: January 25 – March 11, 2013

Supplemental SAR Informal Comment Period: January 25 – March 11, 2013

RSAW Posted for Industry Comments: January 25 – March 11, 2013

Upcoming:

Initial Ballot and Non-Binding Poll: March 1 – March 11, 2013

[Now Available](#)

A formal comment period for **PRC-025-1** – Generator Relay Loadability is open through **8 p.m. Eastern on Monday, March 11, 2013** and ballot pools are forming through **8 a.m. Monday, February 25, 2013** (please note that ballot pools close at 8 a.m. Eastern and mark

your calendar accordingly).

An initial ballot of **PRC-025-1** and non-binding poll of the associated VRFs and VSLs will also be conducted during this period, beginning on **Friday, March 1, 2013** through **8 p.m. Eastern on Monday, March 11, 2013**.

Alongside the comment period, three additional documents will be posted for industry comment: a draft cost effective analysis (CEA), a supplemental SAR, and a draft Reliability Standard Audit Worksheet (RSAW).

In response to concerns expressed by stakeholders and regulators, NERC has developed a Cost Effective Analysis Process (CEAP) to introduce the concept of cost consideration and effectiveness into the development of new and revised standards. As part of the pilot of the CEAP, NERC is proposing to conduct a CEA to provide information about cost impacts of draft Reliability Standards and their relative effectiveness, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of the standard. The revisions under Project 2010-13.2 have been deemed to be required to meet an adequate level of reliability, and therefore, "Phase I" of the CEAP (a cost impact assessment) is unnecessary. A pilot of "Phase II" of the CEAP, the CEA, is posted for industry comment through **8 p.m. Eastern on Monday, March 11, 2013**. More information about the CEAP is available on [the project page](#).

A supplemental SAR has also been developed to revise PRC-023-2 and is posted for an informal comment period.

Finally, PRC-025-1 was drafted in conjunction with the development of its RSAW, which is posted for an informal comment period.

Instructions for Joining Ballot Pool(s)

Ballots pools are being formed for the standard and non-binding poll for PRC-025-1. Registered Ballot Body members must join both ballot pools to be eligible to vote in the balloting of PRC-025-1 and to submit an opinion for the non-binding poll of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: [Join Ballot Pool](#).

During the pre-ballot window, members of the ballot pool may communicate with one another by using the "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list servers for the ballot pools are:

Initial ballot: bp-2010-13.2_PRC-025-1_in@nerc.com

Non-binding poll: bp-2010-13.2_NB_PRC-025_in@nerc.com

Instructions for Commenting

A formal comment period is open for PRC-025-1 through **8 p.m. Eastern on Monday, March 11, 2013**. The supplemental SAR to revise PRC-023-2 and CEA have also been posted for industry comment. Please use the links below to the electronic comment forms to submit comments:

[PRC-025-1](#)
[Supplemental SAR](#)
[Cost Effective Analysis](#)

If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the [project page](#).

A comment period on the draft RSAW is open through **8 p.m. Eastern on Monday, March 11, 2013**. The draft RSAW is posted on the NERC Compliance Reliability Standard Audit Worksheet page. Please submit comments on the draft RSAW by using the RSAW feedback form on the [project page](#) and sending to: RSAWfeedback@nerc.net.

Next Steps

An initial ballot will be conducted **March 1, 2013** through 8 p.m. **Monday, March 11, 2013**.

Background

The March 18, 2010 FERC Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In this Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, developing a new Reliability Standard to address generator protective relay loadability, and developing another Reliability Standard to address the operation of protective relays due to power swings. This project's SAR addresses these directives and establishes a three-phase approach to standard development.

Phase I was focused on making the specific modifications to PRC-023-1 and was completed in the approved PRC-023-2 Reliability Standard, which became mandatory on July 1, 2012. This project, Phase II, is focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. This Reliability Standard establishes requirements for the Generator Operator functional entity to set protective relays at a level such that generating units do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service. Phase III, which will follow this project, will focus on developing requirements that address protective relay operations due to stable power swings.

Additional information can be found on the [project page](#).

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller at wendy.muller@nerc.net.

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

Wendy J. Muller**Standards Development Administrator, Standards**

North American Electric Reliability Corporation

3353 Peachtree Road NE, Suite 600 – North Tower

Atlanta, GA 30326

404-446-9735 office | 404-823-1366 cell

wendy.muller@nerc.net

Reliability | Accountability

You are currently subscribed to nercroster as: gzito@npcc.org

To unsubscribe send a blank email to leave-1313746-788835.cd002acd2acbf71e4490539d6ab3820e@listserv.nerc.com

Guidelines and Technical Basis

Introduction

The document, “Power Plant and Transmission System Protection Coordination,” published by the NERC System Protection and Control Subcommittee ([SPCS](#)) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010.¹

The term, “while maintaining reliable [fault](#) protection” in Requirement R1, describes that the [Generator Owner](#) (“responsible entity (~~“Generator Owner”~~)”) is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generation [unit or](#) plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the responsible entity consider both the requirements within this standard and its desired protection goals, and perform modifications to its ~~protective~~ [relays](#) or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be necessary to replace the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the responsible entity must understand the ~~criteria and application~~ [applications](#) of Table 1, Relay Loadability Evaluation Criteria (“Table 1”), in determining the settings that it must ~~install on~~ [apply to](#) each of its load-responsive protective relays to ~~achieve the required~~ [prevent an unnecessary trip of its](#) generator ~~performance~~ during the ~~transient~~ [system](#) conditions anticipated by this standard.

[Applicability](#)

[The drafting team recognizes that some Generator Owners own an interconnection facility \(in some cases labeled a “transmission Facility” or “generator leads”\) between the generator and the interface with the portion of the BES where Transmission Owners take over the ownership. In these cases, the Generator Owners own sole-use Facilities that are connected to the boundary of the interconnected system. Load-responsive protective relays applied by the Generator Owner at the terminals of these Facilities to protect these interconnection Facilities are included in the scope of this standard.](#)

¹ <http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf>

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as “field-forcing,” results in the Reactive Power output exceeding the steady-state capability of the generator and ~~the resultant increase in apparent power~~ may result in operation of generation system load-responsive ~~generator~~ protective ~~functions, relays~~ if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter may will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing ~~and given~~ the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator ~~backup protection, it is important to evaluate~~ load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition ~~during which the generator is not at risk of thermal damage~~.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the generator step-up transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1, are based on 0.85 per unit of Transmission system nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had not other, undesired, behavior occurred.

The dynamic load levels specified in Table 1 under column ~~Pick-Up~~ “Pickup Setting ~~eCriteria,~~” are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the generator step-up transformer. These values are based on ~~values recorded during records from~~ the events leading to the August 14, 2003 blackout, other subsequent ~~sSystem~~ events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified ~~load operating points are believed to criteria~~ represent conservative, but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20% percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options +1a (0.95 per unit) and 2, 1b (0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output, Option ~~3, for example, 1c (simulation)~~ was developed to allow ~~an the responsible~~ entity to simulate the output of a generating unit when the simple calculation is ~~too~~ conservative not adequate to achieve the desired protective ~~function relay~~ setting.

Asynchronous Generator Performance

Asynchronous generators, however, do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before a crowbar function will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. ~~They~~ These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated megawatts (MW).

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1, (i.e., Option., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19), for ~~induction~~ asynchronous generator installations.

Synchronous Generator Simulation Criteria

The responsible entity who elects to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage on the high-side of the generator step-up transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the generator step-up transformer high-side voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in megawatts as reported to the Planning Coordinator or Transmission Planner.

Phase Distance Relay (~~Options 1-4~~ Directional Toward Transmission System (21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup generator step-up transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation units or plants, contributing to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. ~~The Options 1 through 4~~ These options establish criteria for phase distance relays that are directional toward the Transmission system to help

assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

Phase distance protection The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current. ~~When phase distance protection is applied, its function is to provide backup protection for system faults that have not been cleared by Transmission system circuit breakers via their protective relays.~~

Section 4.6.1.1 of IEEE C37.102-2006, “Guide for AC Generator Protection,” describes the purpose of this protection as follows (emphasis added):

*“The distance relay applied for this function is intended to isolate the generator from the power system for a fault ~~which~~that is not cleared by the transmission line breakers. In some cases this relay is set with a very long reach. A condition ~~which~~that causes the generator voltage regulator to boost generator excitation for a sustained period ~~that~~ may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor ~~(sic: This setting can be re-stated in terms of ohms as 0.66—0.50 per unit ohms on the machine base.)~~ has been shown to provide good coordination for stable swings, system faults involving ~~infeed~~in-feed, and **normal loading conditions**. However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers **to optimize coordination while still protecting the turbine-generator**. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment ~~blind~~ers ~~binders~~ [sic] can prevent misoperation for these conditions. **Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.** With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be*

set as previously described ~~above~~. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the ~~generator step-up~~GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. ~~Your~~The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and isolated-phase bus with partial coverage of the ~~generator step-up~~GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting.”

~~Table 1, Options 1, 2, and 3, are provided for assessing loadability for synchronous generators. The generator-side voltage during field forcing will be higher than the high-side voltage due to the voltage drop resulting from the Reactive Power flow through the generator step-up transformer. Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage.~~

~~Option 1 accounts for the voltage drop across the generator step-up transformer using a conservative estimate of the generator-side voltage. This is based on referring a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer through the turns ratio.~~

~~Option 2 uses a calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This option accounts for the voltage drop through the generator step-up transformer, including the turns ratio and impedance.~~

~~Option 3 uses a simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The responsible entity must perform simulations to determine the actual performance of its generator. The responsible entity that elects to determine the synchronous generator performance on which to base phase distance relay settings may simulate the response of a generator to depressed Transmission system by lowering the Transmission system voltage on the high-side of the generator step-up transformer. This can be simulated by means such as modeling switching of a shunt reactor on the Transmission system to lower the generator step-up transformer high-side voltage to 0.85 per unit prior to field forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator holding the assigned voltage schedule while at 100% of the maximum seasonal gross Real Power capability value as reported to the Planning Coordinator.~~

~~Option 4 is based on a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer. Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Since asynchronous generators~~

~~do not produce as much reactive power as synchronous generators, the voltage rise due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator side based on the generator step-up transformer's turns ratio. The aggregate megavoltampere (MVA) output is determined by summing the total nameplate MW and megavoltampere reactive (Mvar) capability of the generation equipment behind the relay. This should also include any static or dynamic reactive power devices that contribute to the power flow through the relay.~~

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability ~~(i.e., field forcing).~~

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may restrict the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. The examples in Appendix E ~~“of the Power Plant and Transmission System Protection Coordination,” published by the NERC System Protection and Control Subcommittee, technical reference document~~ illustrate the potential for encroaching on the generating unit capability.

~~If an entity is unable to meet the criteria established within Table 1, while maintaining reliable protection, the entity will need to utilize different protective relays or protection philosophies such that both goals can be met.~~

Generator Phase

Phase Time Overcurrent Relay (51)

~~See section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output based on whether the generator operates synchronous or asynchronous.~~

Phase Time Overcurrent Relay – Voltage-Restrained (Options 5-851V-R)

~~Generator Phase time overcurrent~~ voltage-restrained ~~phase overcurrent~~ relays, (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or

both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation units or plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by ~~Voltage Restrained~~ voltage-restrained and ~~Voltage Controlled~~ voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Table 1, Options 5 through 8, establish criteria for phase

Phase Time Overcurrent Relay – Voltage Controlled (51V-C)

Phase time overcurrent voltage-controlled relays which change their sensitivity (51V-C), enabled as a function of voltage to help assure that generators, to the degree possible, will provide system support during disturbances in an effort to minimize the scope of those disturbances. These devices, are variably referred to by IEEE function numbers (51V), (51R), (51VR), (, 51C, 51VC, 51V/R), (C, 51V-R), C, or other terms. The criteria provided for these relays are very similar to those provided for phase distance relays in Options 1 through 4. See clause section 3.10 of “the Power Plant and Transmission System Protection Coordination,” published by the NERC System Protection and Control Subcommittee (SPCS) technical reference document for a detailed discussion of this protection function.

~~Refer to the discussion under Option 4 technical basis concerning asynchronous and inverter based generation.~~

Generator Phase Directional Time Overcurrent Relays—Voltage Controlled (Option 9) Relay – Directional Toward Transmission System (67)

~~Generator voltage-controlled overcurrent relays, enabled as a function of voltage, are applied for the purpose of primary or backup generator step-up transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generation plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by Voltage Restrained and Voltage Controlled protection functions together, and many other generators were tripped by unknown protection functions.~~

~~Table 1, Option 9, establishes criterion for phase overcurrent relays which are enabled as a function of voltage to help assure that generators, to the degree possible, will provide system support during disturbances in an effort to minimize the scope of those disturbances. These devices are variably referred to by IEEE function numbers (51V), (51C), (51VC), (51V/C), (51V-C), or other terms. See clause section 3.109.2 of “the Power Plant and Transmission System Protection Coordination,” published by the NERC System Protection and Control Subcommittee technical reference document for a detailed discussion of this the phase time overcurrent protection function. The basis for setting directional and non-directional time overcurrent relays are similar. Note that the setting criteria for a voltage control setting of less established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than 0.75~~

~~per unit of the nominal~~ establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator voltage is output based on whether the generator operates synchronous or asynchronous.

Table 1, Options

Introduction

The margins in these options are based on guidance found in “the Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the generator step-up transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved.,” published by the NERC SPCS. This calculation is a more involved, more precise setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element is set less than the calculated impedance derived from 115% of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage (“voltage-restrained”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer

(excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage ~~is~~are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

~~Refer to the discussion under~~

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Option 4 ~~technical basis concerning~~)

Table 1, Option 4 is provided for assessing loadability for asynchronous ~~and inverter~~ generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)

Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage (“voltage-restrained”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is

calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 5, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer ~~Phase Time Overcurrent Relay (Options 10-12)~~(Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Option 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. ~~Table 1, Options 10 through 12, establish criteria for the generator protective~~

~~relays to prevent the generator step-up transformer phase time overcurrent relays from operating during the dynamic conditions anticipated by this standard. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.~~

~~The stressed system conditions, anticipated by Options 10 through 12, reflect a 0.85 per unit Transmission system voltage; therefore, establishes that the ampere value used for applying the generator step-up transformer phase time overcurrent relay be calculated from the apparent power addressed within the Table 1, with application of a 0.85 per unit Transmission system voltage.~~

~~Options 10, 7a, 7b, and 11 apply to 7c, are provided for assessing loadability for generator step-up transformers connected to applying phase distance relays that are directional toward the Transmission system on synchronous generators. Option 12 only applies to generator step-up transformers connected to asynchronous generators (including inverter based installations). that are connected to the generator-side of the generator step-up transformer of a synchronous generator.~~

~~Please see clause~~ Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 7a.

Option 7c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers.

Note that the setting criteria established within these options differ from section 3.9.2 of “the Power Plant and Transmission System Protection Coordination,” published by the NERC System Protection and Control Subcommittee for a detailed discussion of this protection function. However, the setting criteria established within Options 10-12 differ from that suggested in this paper. technical reference document. Rather than establishing a uniform setting threshold of 200% percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for generator step-up transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side or high-side of the generator step-up transformer of a synchronous generator.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on whether the generator operates synchronous or asynchronous a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.

Refer to the discussion under Option 4 technical basis concerning asynchronous 8c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 8a and inverter-based 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Distance~~Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 13, 14, 15, 9a, 9b and 169c)

~~The~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph ~~112~~104, directs that NERC address relay loadability for protective relays applied ~~for system backup protection~~. ~~In paragraph 114, FERC further explains that their concern applies whether on~~ generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of a synchronous generator.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 9c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 10)

Table 1, Option 10 is provided for assessing loadability for generator step-up transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 10, the impedance element is set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Options 11a and 11b)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11a, address those relays ~~are~~ generator step-up transformer phase time overcurrent relays installed on the low-side (i.e., generator ~~terminals or on the generator-side~~) of the generator step-up transformer. ~~Their concerns regarding~~ of an asynchronous generator, and Option 11b addresses those relays ~~connected to~~ installed on the high-side (i.e., line-side) of the generator ~~terminals are addressed in Options 1, 2, 3, and 4 for the generator itself; Table 1, Options 13, 14, 15, and 16, for generator step-up transformer distance relays address those connected to the generator side of the generator step-up transformer of an asynchronous generator.~~

~~The generator protective relays in Options 13, 14, 15, and 16 prevent generator step-up transformer phase distance relays from operating during the dynamic conditions anticipated by this standard.~~

Option 11a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer for overcurrent relays installed on the low-side. The voltage drop across the generator step-up transformer is calculated based on a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio of the generator step-up transformer. This is a simple calculation that approximates the stressed system conditions.

Where the relay current is supplied from the generator bus, Option 11a, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio. Where the relay current is supplied from the high-side of the transformer, it is necessary to assess loadability using the high-side nominal voltage in Option 11b.

For Options 11a and 11b, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability for generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of an asynchronous generator.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit system nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer

(excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the generator step-up transformer's turns ratio.

For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (51) (Option 17) 13a and 13b

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of unit auxiliary transformer(s) (“UAT”) that supply normal station service for a generating unit. ~~The~~ For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, ~~Option 17~~, Options 13a and 13b provide two options for ~~auxiliary transformers~~ addresses addressing phase time overcurrent relays ing protecting ~~auxiliary transformers that are used to provide overall auxiliary power to the generating station when~~ UATs. The transformer high-side winding may be directly connected to the transmission grid or ~~at the generator is running (regardless of where these transformers~~ isolated phase bus (IPB) or iso-phase bus. Phase time overcurrent relaying applied to the UAT that act to trip the generator directly or via lockout or auxiliary tripping relay are to be compliant with the relay setting criteria in this standard. Phase time overcurrent relaying applied to the UAT that results in a generator runback are ~~connected). This discussion refers to each~~ not a part of these transformers as a “unit auxiliary transformer” or “UAT.” If the UAT trips, it will result in tripping of the generator itself, either ~~directly or indirectly. this standard.~~ Although the UAT is not directly in the output path from the generator to the system, it is an essential component for operation of the generating unit or plant.

Refer to the figures below for example configurations:

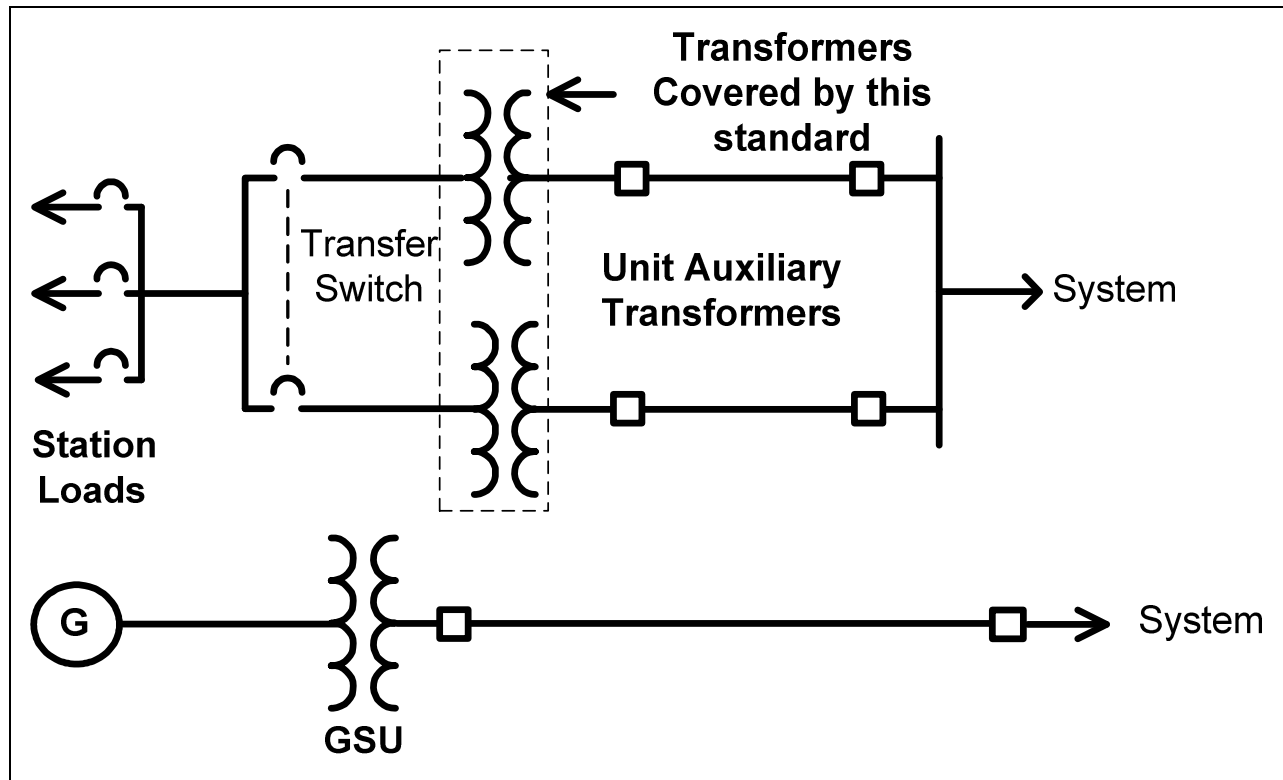


Figure-1 – Auxiliary Power System (~~I~~ndependent from ~~G~~enerator)

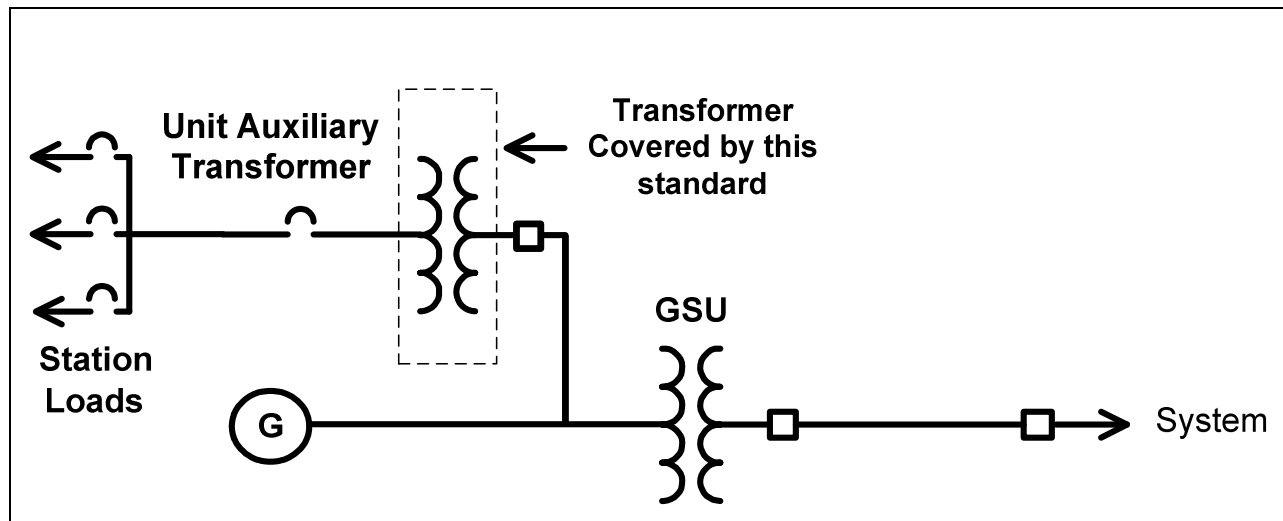


Figure-2 – Typical ~~Auxiliary Power System~~auxiliary power system for ~~Power Plants~~generation units or plants.

The UATs supplying power to the ~~plant's unit or plant~~ electrical auxiliaries are sized to accommodate ~~for~~ the maximum expected ~~auxiliary UAT~~ load demand at the highest generator output. Although the MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b calculate the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding or each low-side winding of the UAT based on relay location. Consideration of the voltage drop across the transformer is not necessary.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Planning Coordinator or Transmission Planner. This allows for a reduced setting pickup compared to Option 13a but does allow for an entity's relay setting philosophy. Because loading characteristics may be different from one load bus to another, the phase current measurement will have to be verified at each relay location protecting the transformer. The phase time overcurrent relay pickup setting criteria is established at 150 percent of the measured value for each relay location. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Planning Coordinator or Transmission Planner.

The performance of the auxiliaryUAT loads during stressed system conditions (depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of auxiliaryUAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150% percent from that used elsewhere in this standard (i.e.g., 115%) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150% percent of maximum nameplate MVA rating at 1.0 per unit generator bus voltage wouldwill provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased auxiliaryUAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Generator Interconnection Facilities (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Option 14a and 14b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 14a and 14b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the generator step-up transformer phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary.

For Option 14a, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Generator Interconnection Facilities (Synchronous Generators) Phase Time Overcurrent Relay (51) (Option 15a and 15b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 15a and 15b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the generator step-up transformer phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary.

For Option 15a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Generator Interconnection Facilities (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 16a and 16b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 16a and 16b, establish criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 16a and 16b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the generator step-up transformer phase directional time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up transformer is not necessary.

For Option 16a, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Planning Coordinator or Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Generator Interconnection Facilities (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant.

For Option 17, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Generator Interconnection Facilities (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the MVA. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant.

For Option 18, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Generator Interconnection Facilities (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than

establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the MVA. Asynchronous generators do not produce as much reactive power as synchronous generators; the voltage drop due to reactive power flow through the generator step-up transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate megavoltampere (MVA) output at rated power factor including the Mvar output of any static or dynamic reactive power devices. This is determined by summing the total nameplate MW and Mvar capability of the generation equipment behind the relay and any static or dynamic reactive power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations

Input Descriptions

Input Values

Generator nameplate (MVA @ rated pf):

$$GEN_{nameplate} = 903 \text{ MVA}$$

$$pf = 0.85$$

Generator rated voltage (Line-to-Line):

$$V_{gen} = 22 \text{ kV}$$

Real Power output in MW as reported to the PC or TP:

$$P_{reported} = 767.6 \text{ MW}$$

Generator step-up transformer impedance (903 MVA base):

$$Z_{gsu} = 12.14\%$$

Generator step-up transformer turns ratio:

$$GSU_{ratio} = \frac{22 \text{ kV}}{346.5 \text{ kV}}$$

High-side nominal system voltage (Line-to-Line):

$$V_{nom} = 345 \text{ kV}$$

Current transformer ratio:

$$CT_{ratio} = \frac{25000}{5}$$

Potential transformer ratio:

$$PT_{ratio} = \frac{200}{1}$$

Auxiliary transformer nameplate:

$$UAT_{nameplate} = 60 \text{ MVA}$$

Auxiliary low-side voltage:

$$V_{uat} = 13.8 \text{ kV}$$

Auxiliary current transformer:

$$CT_{uat} = \frac{5000}{5}$$

Transformer High Voltage CT:

$$CT_{HV} = \frac{2000}{5}$$

Reactive Power output of static reactive device:

$$MVAR_{static} = 100 \text{ Mvar}$$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (21) directional toward the Transmission system.

Real Power output (P):

$$\text{Eq. (1)} \quad P = GEN_{nameplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (2)} \quad Q = 150\% \times P$$

$$Q = 1.5 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (3)} \quad V_{gen} = 0.95 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 20.81 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (4)} \quad S = P_{reported} + jQ$$

$$S = 767.6 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1383.7 \angle 56.3^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

$$\text{Eq. (5)} \quad Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81 \text{ kV})^2}{1383.7 \angle -56.3^\circ \text{ MVA}}$$

$$Z_{pri} = 0.3130 \angle 56.3^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (6)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

Example Calculations: Option 1a

$$Z_{sec} = 0.3130 \angle 56.3^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.3130 \angle 56.3^\circ \Omega \times 25$$

$$Z_{sec} = 7.8238 \angle 56.3^\circ \Omega$$

To satisfy the 115% margin in Option 1a:

$$\text{Eq. (7)} \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec \text{ limit}} = \frac{7.8238 \angle 56.3^\circ \Omega}{1.15}$$

$$Z_{sec \text{ limit}} = 6.8033 \angle 56.3^\circ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

$$\text{Eq. (8)} \quad Z_{max} < \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{transient \text{ load angle}})}$$

$$Z_{max} < \frac{6.8033 \Omega}{\cos(85.0^\circ - 56.3^\circ)}$$

$$Z_{max} < \frac{6.8033 \Omega}{0.8771}$$

$$Z_{max} < 7.7561 \angle 85.0^\circ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance (21) directional toward the Transmission system relay. This option requires calculating low-side voltage taking into account voltage drop across the generator step-up transformer. Similarly these calculations may be applied to Option 7b for generator step-up transformers applying a phase distance (21) directional toward the Transmission system relay.

Real Power output (P):

$$\text{Eq. (9)} \quad P = GEN_{nameplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Example Calculations: Options 1b and 7b

Reactive Power output (Q):

$$\text{Eq. (10)} \quad Q = 150\% \times P$$

$$Q = 1.5 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base:

Real Power output (P):

$$\text{Eq. (11)} \quad P_{pu} = \frac{P}{MVA_{base}}$$

$$P_{pu} = \frac{767.6 \text{ MW}}{767.6 \text{ MVA}}$$

$$P_{pu} = 1.0 \text{ p.u.}$$

Reactive Power output (Q):

$$\text{Eq. (12)} \quad Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3 \text{ Mvar}}{767.6 \text{ MVA}}$$

$$Q_{pu} = 1.5 \text{ p.u.}$$

Transformer impedance (X_{pu}):

$$\text{Eq. (13)} \quad X_{pu} = X_{GSU(ola)} \times \left(\frac{MVA_{base}}{MVA_{GSU}} \right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6 \text{ MVA}}{903 \text{ MVA}} \right)$$

$$X_{pu} = 0.1032 \text{ p.u.}$$

Use the formula below; calculate the low-side generator step-up transformer voltage ($V_{low-side}$) using 0.85 p.u. high-side voltage ($V_{high-side}$). Estimate initial low-side voltage to be 0.95 p.u. Repeat the calculation if necessary until $V_{low-side}$ converges:

$$\text{Eq. (14)} \quad \theta_{low-side} = \frac{\sin^{-1}(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}$$

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.95 \times 0.85)}$$

Example Calculations: Options 1b and 7b

$$\theta_{low-side} = \frac{5.92^\circ}{0.8075}$$

$$\theta_{low-side} = 7.3^\circ$$

$$\text{Eq. (15)} \quad |V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.3^\circ) \pm \sqrt{|0.85|^2 \times \cos(7.3^\circ)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9918 \pm \sqrt{0.7225 \times 0.9837 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8430 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9981 \text{ p. u.}$$

Use the new estimated $V_{low-side}$ value of 0.9981 per unit for the second iteration:

$$\text{Eq. (16)} \quad \theta_{low-side} = \frac{\sin^{-1}(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}$$

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.9981 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92^\circ}{0.8484}$$

$$\theta_{low-side} = 7.0^\circ$$

$$\text{Eq. (17)} \quad |V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.0^\circ) \pm \sqrt{|0.85|^2 \times \cos(7.0^\circ)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9926 \pm \sqrt{0.7225 \times 0.9852 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8437 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9987 \text{ p. u.}$$

Example Calculations: Options 1b and 7b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$

$$V_{bus} = 0.9987 \text{ p.u.} \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{bus} = 21.88 \text{ kV}$$

Apparent power (S):

Eq. (19) $S = P_{reported} + jQ$

$$S = 767.6 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1383.7 \angle 56.3^\circ$$

Primary Impedance (Z_{pri}):

Eq. (20) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.88 \text{ kV})^2}{1383.7 \angle -56.3^\circ \text{ MVA}}$$

$$Z_{pri} = 0.3458 \angle 56.3^\circ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.3458 \angle 56.3^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.3458 \angle 56.3^\circ \Omega \times 25$$

$$Z_{sec} = 8.6462 \angle 56.3^\circ \Omega$$

To satisfy the 115% margin in the requirement in Options 1b and 7b:

Eq. (22) $Z_{sec \text{ limit}} = \frac{Z_{sec}}{115\%}$

$$Z_{sec \text{ limit}} = \frac{8.6462 \angle 56.3^\circ \Omega}{1.15}$$

$$Z_{sec \text{ limit}} = 7.5185 \angle 56.3^\circ \Omega$$

Example Calculations: Options 1b and 7b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , and then the maximum allowable impedance reach is:

$$\text{Eq. (23)} \quad Z_{max} < \frac{|Z_{sec\ limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.5185\Omega}{\cos(85.0^\circ - 56.3^\circ)}$$

$$Z_{max} < \frac{7.5185\ \Omega}{0.8771}$$

$$Z_{max} < 8.5715 \angle 85.0^\circ \ \Omega$$

Example Calculations: Option 1c

This option requires simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

$$\text{Eq. (24)} \quad P = GEN_{nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

$$\text{Eq. (25)} \quad Q = 150\% \times P$$

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (26)} \quad V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV} \right)$$

Example Calculations: Option 2a

$$V_{gen} = 20.81 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (27)} \quad S = P_{reported} + jQ$$

$$S = 767.6 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1383.7 \angle 56.3^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (28)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1383.7 \text{ MVA}}{1.73 \times 20.81 \text{ kV}}$$

$$I_{pri} = 38389.9 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (29)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{38389.9 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.678 \text{ A}$$

To satisfy the 115% margin in Option 2a:

$$\text{Eq. (30)} \quad I_{sec \text{ limit}} > I_{sec} \times 115\%$$

$$I_{sec \text{ limit}} > 7.678 \text{ A} \times 1.15$$

$$I_{sec \text{ limit}} > 8.83 \text{ A}$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

$$\text{Eq. (31)} \quad P = GEN_{nameplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

Example Calculations: Option 2b

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (32)} \quad Q = 150\% \times P$$

$$Q = 1.5 \times 767.6 \text{ MW}$$

$$Q = 1151 \text{ Mvar}$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base.

Real Power output (P):

$$\text{Eq. (33)} \quad P_{pu} = \frac{P}{MVA_{base}}$$

$$P_{pu} = \frac{767.6 \text{ MW}}{767.6 \text{ MVA}}$$

$$P_{pu} = 1.0 \text{ p.u.}$$

Reactive Power output (Q):

$$\text{Eq. (34)} \quad Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3 \text{ Mvar}}{767.6 \text{ MVA}}$$

$$Q_{pu} = 1.5 \text{ p.u.}$$

Transformer impedance:

$$\text{Eq. (35)} \quad X_{pu} = X_{GSU(ola)} \times \left(\frac{MVA_{base}}{MVA_{GSU}} \right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6 \text{ MVA}}{903 \text{ MVA}} \right)$$

$$X_{pu} = 0.1032 \text{ p.u.}$$

Use the formula below; calculate the low-side generator step-up transformer voltage ($V_{low-side}$) using 0.85 p.u. high-side voltage ($V_{high-side}$). Estimate initial low-side voltage to be 0.95 p.u. Repeat the calculation if necessary until $V_{low-side}$ converges:

$$\text{Eq. (36)} \quad \theta_{low-side} = \frac{\sin^{-1}(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}$$

Example Calculations: Option 2b

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.95 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92^\circ}{0.8075}$$

$$\theta_{low-side} = 7.3^\circ$$

$$\text{Eq. (37)} \quad |V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.3^\circ) \pm \sqrt{|0.85|^2 \times \cos(7.3^\circ)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9918 \pm \sqrt{0.7225 \times 0.9837 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8430 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9981 \text{ p.u.}$$

Use the new estimated $V_{low-side}$ value of 0.9981 per unit for the second iteration:

$$\text{Eq. (38)} \quad \theta_{low-side} = \frac{\sin^{-1}(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}$$

$$\theta_{low-side} = \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.9981 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92^\circ}{0.8484}$$

$$\theta_{low-side} = 7.0^\circ$$

$$\text{Eq. (39)} \quad |V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos(\theta_{low-side})^2 + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(7.0^\circ) \pm \sqrt{|0.85|^2 \times \cos(7.0^\circ)^2 + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9926 \pm \sqrt{0.7225 \times 0.9852 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8437 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.9987 \text{ p.u.}$$

Example Calculations: Option 2b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (40) $V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$

$$V_{bus} = 0.9987 \text{ p.u.} \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{bus} = 21.88 \text{ kV}$$

Apparent power (S):

Eq. (41) $S = P_{reported} + jQ$

$$S = 767.6 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1383.7 \angle 56.3^\circ \text{ MVA}$$

Primary current (I_{pri}):

Eq. (42) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1383.7 \text{ MVA}}{1.73 \times 21.88 \text{ kV}}$$

$$I_{pri} = 36519.8 \text{ A}$$

Secondary current (I_{sec}):

Eq. (43) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{36519.8 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.304 \text{ A}$$

To satisfy the 115% margin in Option 2b:

Eq. (44) $I_{sec \text{ limit}} > I_{sec} \times 115\%$

$$I_{sec \text{ limit}} > 7.304 \text{ A} \times 1.15$$

$$I_{sec \text{ limit}} > 8.4 \text{ A}$$

Example Calculations: Option 2c

This option requires simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (51V-C) – voltage controlled relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Real Power output (P):

$$\text{Eq. (45)} \quad P = GEN_{nameplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (46)} \quad Q = 150\% \times P$$

$$Q = 1.5 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (47)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

The voltage setting shall be set less than 75% of the generator bus voltage:

$$\text{Eq. (48)} \quad V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9 \text{ kV} \times 0.75$$

$$V_{setting} < 16.429 \text{ kV}$$

Example Calculations: Options 4, 10, and 17

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance (21) – directional toward the Transmission system relay. Similarly, these calculations may also be applied to other asynchronous applications, including Option 17 for generator step-up transformers and lines that radially connect a generating plant to the Transmission system. In this application it was assumed 100Mvar of static compensation was added.

Real Power output (P):

$$\text{Eq. (49)} \quad P = GEN_{nameplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (50)} \quad Q = MVAR_{static} + GEN_{nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 100 \text{ Mvar} \times 475.7 \text{ Mva}$$

$$Q = 575.7 \text{ Mvar}$$

Options 4, 10, and 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (51)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (52)} \quad S = P_{reported} + jQ$$

$$S = 767.6 \text{ MW} + j575.7 \text{ Mvar}$$

$$S = 959.5 \angle 36.9^\circ \text{ MVA}$$

$$\theta_{transient \text{ load angle}} = 36.9^\circ$$

Primary impedance (Z_{pri}):

$$\text{Eq. (53)} \quad Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9 \text{ kV})^2}{959.5 \angle -36.9^\circ \text{ MVA}}$$

$$Z_{pri} = 0.5001 \angle 36.9^\circ \Omega$$

Example Calculations: Options 4, 10, and 17

Secondary impedance (Z_{sec}):

$$\text{Eq. (54)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.5001 \angle 36.9^\circ \Omega \times \frac{25000}{\frac{5}{200}} \times \frac{1}{1}$$

$$Z_{sec} = 0.5001 \angle 36.9^\circ \Omega \times 25$$

$$Z_{sec} = 12.502 \angle 36.9^\circ \Omega$$

To satisfy the 130% margin in Option 1a:

$$\text{Eq. (55)} \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{130\%}$$

$$Z_{sec \text{ limit}} = \frac{12.502 \angle 36.9^\circ \Omega}{1.30}$$

$$Z_{sec \text{ limit}} = 9.617 \angle 36.9^\circ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , and then the maximum allowable impedance reach is:

$$\text{Eq. (56)} \quad Z_{max} < \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{transient \text{ load angle}})}$$

$$Z_{max} < \frac{9.617 \Omega}{\cos(85.0^\circ - 36.9^\circ)}$$

$$Z_{max} < \frac{9.617 \Omega}{0.6678}$$

$$Z_{max} < 14.401 \angle 85.0^\circ \Omega$$

Example Calculations: Option 5

This represents the calculation for asynchronous generators applying a phase time overcurrent (51V-R) – voltage restrained relay. In this application it was assumed 100Mvar of static compensation was added. Similarly, Option 6 uses the same calculation for asynchronous generators.

Real Power output (P):

$$\text{Eq. (57)} \quad P = GEN_{nameplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

Example Calculations: Option 5

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (58)} \quad Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 100 \text{ Mvar} + 475.7 \text{ Mvar}$$

$$Q = 575.7 \text{ Mvar}$$

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (59)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (60)} \quad S = P_{reported} + jQ$$

$$S = 767.6 \text{ MW} + j575.7 \text{ Mvar}$$

$$S = 959.5 \angle 36.9^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (61)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{959.5 \text{ MVA}}{1.73 \times 21.9 \text{ kV}}$$

$$I_{pri} = 25295.3 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (62)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{25295.3 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 5.06 \text{ A}$$

Example Calculations: Option 5

To satisfy the 130% margin in Option 5:

$$\text{Eq. (63)} \quad I_{\text{sec limit}} > I_{\text{sec}} \times 130\%$$

$$I_{\text{sec limit}} > 5.06 \text{ A} \times 1.30$$

$$I_{\text{sec limit}} > 6.58 \angle -36.9^\circ \text{ A}$$

Example Calculations: Option 8a, 8b, 9a, 9b, 15a, and 16a

Option 8a represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to a synchronous generator. Similarly, these calculations can be applied to other synchronous generator applications, including Option 9a for generator step-up transformers applying a phase directional time overcurrent (67) directional toward the Transmission system relay, and Option 15a and 16a for lines that radially connect a generating plant to the Transmission system using a phase time overcurrent (51) and phase directional time overcurrent (67) directional toward the Transmission system relay, respectively. Options 8b and 9b use the same process, except the bus voltage is 0.85 per unit is used instead of 0.95 and excludes the generator step-up (GSU) impedance.

This example uses Option 8b as an example.

Real Power output (P):

$$\text{Eq. (64)} \quad P = \text{GEN}_{\text{namplate}} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (65)} \quad Q = 150\% \times P$$

$$Q = 1.5 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Option 8b, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

$$\text{Eq. (66)} \quad V_{\text{bus}} = 0.85 \text{ p.u.} \times V_{\text{nom}}$$

$$V_{\text{gen}} = 0.85 \times 345 \text{ kV}$$

$$V_{\text{gen}} = 293.25 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (67)} \quad S = P_{\text{reported}} + jQ$$

Example Calculations: Option 8a, 8b, 9a, 9b, 15a, and 16a

$$S = 767.6 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1383.7 \angle 56.3^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (68)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1383.7 \text{ MVA}}{1.73 \times 293.25 \text{ kV}}$$

$$I_{pri} = 2724.3 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (69)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{2724.3 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 0.545 \text{ A}$$

To satisfy the 115% margin in Option 8a:

$$\text{Eq. (70)} \quad I_{sec \text{ limit}} > I_{sec} \times 115\%$$

$$I_{sec \text{ limit}} > 0.545 \text{ A} \times 1.15$$

$$I_{sec \text{ limit}} > 0.627 \text{ A}$$

Example Calculations: Options 7c, 8c, 9c, 14b, 15b, and 16b

These options require simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.

Example Calculations: Options 11a and 12

Option 11 represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent (67) directional toward the Transmission system relay. In this application it was assumed 100Mvar of static compensation was added.

Real Power output (P):

$$\text{Eq. (71)} \quad P = GEN_{namplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (72)} \quad Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 100 \text{ Mvar} + 475.7 \text{ Mvar}$$

$$Q = 575.7 \text{ Mvar}$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (73)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (74)} \quad S = P_{reported} + jQ$$

$$S = 767.6 \text{ MW} + j575.7 \text{ Mvar}$$

$$S = 959.5 \angle 36.9^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (75)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{959.5 \text{ MVA}}{1.73 \times 21.9 \text{ kV}}$$

$$I_{pri} = 25295 \text{ A}$$

Example Calculations: Options 11a and 12

Secondary current (I_{sec}):

$$\begin{aligned}\text{Eq. (76)} \quad I_{sec} &= \frac{I_{pri}}{CT_{ratio}} \\ I_{sec} &= \frac{25295 \text{ A}}{\frac{25000}{5}} \\ I_{sec} &= 5.059 \text{ A}\end{aligned}$$

To satisfy the 130% margin in Options 11 and 12:

$$\begin{aligned}\text{Eq. (77)} \quad I_{sec \text{ limit}} &> I_{sec} \times 130\% \\ I_{sec \text{ limit}} &> 5.059 \text{ A} \times 1.30 \\ I_{sec \text{ limit}} &> 6.575 \text{ A}\end{aligned}$$

Example Calculations: Option 13a and 13b

Option 13a of the unit auxiliary transformer (UAT) assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Planning Coordinator or Transmission Planner.

Primary current (I_{pri}):

$$\begin{aligned}\text{Eq. (78)} \quad I_{pri} &= \frac{UAT_{nameplate}}{\sqrt{3} \times V_{uat}} \\ I_{pri} &= \frac{60 \text{ MVA}}{1.73 \times 13.8 \text{ kV}} \\ I_{pri} &= 2510.2 \text{ A}\end{aligned}$$

Secondary current (I_{sec}):

$$\begin{aligned}\text{Eq. (79)} \quad I_{sec} &= \frac{I_{pri}}{CT_{uat}} \\ I_{sec} &= \frac{2510.2 \text{ A}}{\frac{5000}{5}} \\ I_{sec} &= 2.51 \text{ A}\end{aligned}$$

Example Calculations: Option 13a and 13b

To satisfy the 150% margin in Option 13a:

$$\text{Eq. (80)} \quad I_{\text{sec limit}} > I_{\text{sec}} \times 150\%$$

$$I_{\text{sec limit}} > 2.51 \text{ A} \times 1.50$$

$$I_{\text{sec limit}} > 3.77 \text{ A}$$

Example Calculations: Option 14a

Option 14a represents the calculation for lines that radially connect an asynchronous generating plant to the Transmission system for a phase directional time overcurrent (67) directional toward the Transmission system relay.

Real Power output (P):

$$\text{Eq. (81)} \quad P = GEN_{\text{namplate}} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (82)} \quad Q = 150\% \times P$$

$$Q = 1.5 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the generator step-up (GSU) voltage (V_{nom}):

$$\text{Eq. (83)} \quad V_{\text{bus}} = 0.85 \text{ p.u.} \times V_{\text{nom}}$$

$$V_{\text{gen}} = 0.85 \times 345 \text{ kV}$$

$$V_{\text{gen}} = 293.25 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (84)} \quad S = P_{\text{reported}} + jQ$$

$$S = 767.6 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1383.7 \angle 56.3^\circ \text{ MVA}$$

$$\theta_{\text{transient load angle}} = 56.3^\circ$$

Example Calculations: Option 14aPrimary impedance (Z_{pri}):

$$\text{Eq. (85)} \quad Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25 \text{ kV})^2}{1383.7 \angle -56.3^\circ \text{ MVA}}$$

$$Z_{pri} = 62.1481 \angle 56.3^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (86)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 62.1481 \angle 56.3^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 62.1481 \angle 56.3^\circ \Omega \times 25$$

$$Z_{sec} = 1553.7 \angle 56.3^\circ \Omega$$

To satisfy the 115% margin in Option 14a:

$$\text{Eq. (87)} \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec \text{ limit}} = \frac{1553.7 \angle 56.3^\circ \Omega}{1.15}$$

$$Z_{sec \text{ limit}} = 1351.0 \angle 56.3^\circ \Omega$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , and then the maximum allowable impedance reach is:

$$\text{Eq. (88)} \quad Z_{max} < \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{transient \text{ load angle}})}$$

$$Z_{max} < \frac{1351.0 \Omega}{\cos(85.0^\circ - 56.3^\circ)}$$

$$Z_{max} < \frac{1651.0 \Omega}{0.8771}$$

$$Z_{max} < 1870.8 \angle 85.0^\circ \Omega$$

Example Calculations: Options 11b, 18, and 19

Option 11b represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, Option 18 may also be applied here as well for generation interconnection Facilities and Option 19 for the phase directional time overcurrent (67) directional toward the Transmission system relays for generation interconnection Facilities. In this application it was assumed 100 Mvar of static compensation was added.

Real Power output (P):

$$\text{Eq. (89)} \quad P = GEN_{nameplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (90)} \quad Q = MVAR_{static} + GEN_{nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 100 \text{ Mvar} + 475.7 \text{ Mvar}$$

$$Q = 575.7 \text{ Mvar}$$

Options 11b, 18, and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (91)} \quad V_{nom} = 1.0 \text{ p.u.} \times V_{nom}$$

$$V_{gen} = 1.0 \times 345 \text{ kV}$$

$$V_{gen} = 345 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (92)} \quad S = P_{reported} + jQ$$

$$S = 767.6 \text{ MW} + j575.7 \text{ Mvar}$$

$$S = 959.5 \angle 36.9^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (93)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{959.5 \text{ MVA}}{1.73 \times 345 \text{ kV}}$$

$$I_{pri} = 1605 \text{ A}$$

Example Calculations: Options 11b, 18, and 19

Secondary current (I_{sec}):

$$\begin{aligned}\text{Eq. (94)} \quad I_{sec} &= \frac{I_{pri}}{CT_{HV}} \\ I_{sec} &= \frac{1605 \text{ A}}{\frac{2000}{5}} \\ I_{sec} &= 4.014 \text{ A}\end{aligned}$$

To satisfy the 130% margin in Options 11b, 18, and 19:

$$\begin{aligned}\text{Eq. (95)} \quad I_{sec \text{ limit}} &> I_{sec} \times 130\% \\ I_{sec \text{ limit}} &> 4.014 \text{ A} \times 1.30 \\ I_{sec \text{ limit}} &> 5.218 \text{ A}\end{aligned}$$

End of calculations

From: [Guy V. Zito](#)
To: [mbennett@cpv.com](#); [allen.schrivier@fpl.com](#); [david.belanger@exeloncorp.com](#)
Cc: [rsc](#)
Subject: Cost Effectiveness Pilot- NERC Standards Announcement | Project 2010-13.2 Phase 2 of Relay Loadability: Generation | Comment
Period Now Open through Monday, March 11, 2013
Date: Monday, January 28, 2013 9:48:35 AM

Gentlemen,

Would you please ensure your members are aware of the below? This is the first “pilot” use of NERC’s cost effectiveness analysis process CEAP. Now is our first opportunity to provide cost information and alternative more effective solutions (if there are any) formally into the drafting process. The process allows this information to be provided early enough to allow the standard drafting team sufficient time to change the standard to reflect and consider cost effective alternatives which may be available. If we can solicit a strong response from the industry, indicative of support for the process, I will work through the NERC Standards Committee to expand this CEAP, or some variation of it, to all new standards by year’s end.

Thanks for your support,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From: NERC Standards Announcements (Do Not Reply) [mailto:NERC-StandardsAnnouncements-DoNotReply@nerc.net]

Sent: Friday, January 25, 2013 1:16 PM

To: Wendy Muller

Subject: NERC Standards Announcement | Project 2010-13.2 Phase 2 of Relay Loadability: Generation | Comment
Period Now Open through Monday, March 11, 2013

Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation

Ballot Pools Forming: January 25 – February 25, 2013
Formal Comment Period: January 25 – March 11, 2013

Additional Documents Posted for Comment:

Cost Effectiveness Comment Period: January 25 – March 11, 2013
Supplemental SAR Informal Comment Period: January 25 – March 11, 2013
RSAW Posted for Industry Comments: January 25 – March 11, 2013

Upcoming:

Initial Ballot and Non-Binding Poll: March 1 – March 11, 2013

[Now Available](#)

A formal comment period for **PRC-025-1** – Generator Relay Loadability is open through **8 p.m. Eastern on Monday, March 11, 2013** and ballot pools are forming through **8 a.m. Monday, February 25, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

An initial ballot of **PRC-025-1** and non-binding poll of the associated VRFs and VSLs will also be conducted during this period, beginning on **Friday, March 1, 2013** through **8 p.m. Eastern on Monday, March 11, 2013**.

Alongside the comment period, three additional documents will be posted for industry comment: a draft cost effective analysis (CEA), a supplemental SAR, and a draft Reliability Standard Audit Worksheet (RSAW).

In response to concerns expressed by stakeholders and regulators, NERC has developed a Cost Effective Analysis Process (CEAP) to introduce the concept of cost consideration and effectiveness into the development of new and revised standards. As part of the pilot of the CEAP, NERC is proposing to conduct a CEA to provide information about cost impacts of draft Reliability Standards and their relative effectiveness, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of the standard. The revisions under Project 2010-13.2 have been deemed to be required to meet an adequate level of reliability, and therefore, “Phase I” of the CEAP (a cost impact assessment) is unnecessary. A pilot of “Phase II” of the CEAP, the CEA, is posted for industry comment through **8 p.m. Eastern on Monday, March 11, 2013**. More information about the CEAP is available on [the project page](#).

A supplemental SAR has also been developed to revise PRC-023-2 and is posted for an informal comment period.

Finally, PRC-025-1 was drafted in conjunction with the development of its RSAW, which is posted for an informal comment period.

Instructions for Joining Ballot Pool(s)

Ballot pools are being formed for the standard and non-binding poll for PRC-025-1. Registered Ballot Body members must join both ballot pools to be eligible to vote in the balloting of PRC-025-1 and to submit an opinion for the non-binding poll of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: [Join Ballot Pool](#).

During the pre-ballot window, members of the ballot pool may communicate with one another by using the “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list servers for the ballot pools are:

Initial ballot: bp-2010-13.2_PRC-025-1_in@nerc.com

Non-binding poll: bp-2010-13.2_NB_PRC-025_in@nerc.com

Instructions for Commenting

A formal comment period is open for PRC-025-1 through **8 p.m. Eastern on Monday, March**

11, 2013. The supplemental SAR to revise PRC-023-2 and CEA have also been posted for industry comment. Please use the links below to the electronic comment forms to submit comments:

[PRC-025-1](#)

[Supplemental SAR](#)

[Cost Effective Analysis](#)

If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the [project page](#).

A comment period on the draft RSAW is open through **8 p.m. Eastern on Monday, March 11, 2013**. The draft RSAW is posted on the NERC Compliance Reliability Standard Audit Worksheet page. Please submit comments on the draft RSAW by using the RSAW feedback form on the [project page](#) and sending to: RSAWfeedback@nerc.net.

Next Steps

An initial ballot will be conducted **March 1, 2013** through 8 p.m. **Monday, March 11, 2013**.

Background

The March 18, 2010 FERC Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In this Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, developing a new Reliability Standard to address generator protective relay loadability, and developing another Reliability Standard to address the operation of protective relays due to power swings. This project's SAR addresses these directives and establishes a three-phase approach to standard development.

Phase I was focused on making the specific modifications to PRC-023-1 and was completed in the approved PRC-023-2 Reliability Standard, which became mandatory on July 1, 2012. This project, Phase II, is focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. This Reliability Standard establishes requirements for the Generator Operator functional entity to set protective relays at a level such that generating units do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service. Phase III, which will follow this project, will focus on developing requirements that address protective relay operations due to stable power swings.

Additional information can be found on the [project page](#).

Standards Development Process

The [Standards Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller at wendy.muller@nerc.net.

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

Wendy J. Muller
Standards Development Administrator, Standards
North American Electric Reliability Corporation
3353 Peachtree Road NE, Suite 600 – North Tower
Atlanta, GA 30326
404-446-9735 office | 404-823-1366 cell
wendy.muller@nerc.net
Reliability | Accountability

You are currently subscribed to nercroster as: gzito@npcc.org
To unsubscribe send a blank email to leave-1313746-788835.cd002acd2acbf71e4490539d6ab3820e@listserv.nerc.com

Implementation Plan

Project 2010-13.2 - Relay Loadability: Generator

Requested Approvals

- PRC-023-3 – Transmission Relay Loadability

Requested Retirements

- PRC-023-2 – Transmission Relay Loadability

Prerequisite Approvals

- PRC-025-1 – Generator Relay Loadability

A supplemental SAR was approved by the Standards Committee at their January 16-17, 2013 meeting to authorize the drafting team to make changes to PRC-023-2 to comport with the proposed draft PRC-025-1 – Generator Relay Loadability and in order to establish a bright line between the applicability of load-responsive protective relays in the current transmission and the proposed generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The generator relay loadability standard drafting team and industry stakeholders raised a concern about the potential for overlap between existing PRC-023-2 – Transmission Relay Loadability standard, effective in the United States on July 1, 2012, and the proposed PRC-025-1 – Generator Relay Loadability standards. The concern is that there was no bright line to clearly distinguish which load-responsive protective relays pertain to each standard. The drafting team researched the issue and proposed to modify the applicability section of PRC-023-2 to clarify the each functional entity's applicability with respect to which terminal the load-responsive protective relay is connected to within the Transmission system.

General Considerations

The Implementation Plan period reflects consideration that a specific period is not required because no new entity or facilities are subject to compliance. Also, it is expected that implementation plan and period for PRC-023-2 will have been achieved and that it will not need to be considered in conjunction with this revision.

Applicable Entities

- Distribution Provider

- Generator Owner
- Planning Coordinator
- Transmission Owner

Effective Date**New Standard**

PRC-023-3 First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

PRC-023-2 Midnight of the day immediately prior to the Effective Date of PRC-023-2 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-023-3, All requirements

Each Distribution Provider, Generator Owner, Planning Coordinator, and Transmission Owner applicable to this standard shall be 100% compliant on the effective date of the standard according to the jurisdiction.

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be retired or revised when this standard is implemented. If the drafting team is recommending the retirement or revision of a requirement, that text is blue.

Already Approved Standard	Proposed Replacement Requirement(s)
PRC-023-2 4.1. Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 (<i>Circuits Subject to Requirements R1 – R5</i>). 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 (<i>Circuits Subject to Requirements R1 – R5</i>). 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1(<i>Circuits Subject to Requirements R1 – R5</i>), provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators	PRC-023-3 4.1.Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied at the terminals of the ~~to~~ circuits defined in 4.2.1 (<i>Circuits Subject to Requirements R1 – R5</i>). 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied at the terminals of the ~~to~~ circuits defined in 4.2.1 (<i>Circuits Subject to Requirements R1 – R5</i>). 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied at the terminals of the ~~to~~ circuits defined in 4.2.1 (<i>Circuits Subject to Requirements R1 – R5</i>), provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators
Notes: The change in applicability creates a bright line between those load-responsive protective relays that are applicable to PRC-023-3 – Transmission Relay Loadability and the proposed PRC-025-1 – Generator Relay Loadability. This is evident by the minor changes to the applicability text to distinguish the applicability of the relays by which “terminal” the load-responsive protective relay is connected to within the Transmission system.	

A. Introduction

1. Title: Transmission Relay Loadability

2. Number: PRC-023-~~23~~

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. Applicability

4.1. Functional Entity

4.1.1 Transmission Owners~~s~~ with load-responsive phase protection systems as described in PRC-023-~~23~~ - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

4.1.2 Generator Owners~~s~~ with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

4.1.3 Distribution Providers~~s~~ with load-responsive phase protection systems as described in PRC-023-~~23~~ - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinators~~s~~

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

5. Effective Dates

~~The effective dates of the requirements in the PRC-023-2 standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:~~

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First calendar quarter after Board of Trustees adoption
	For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability	First day of the first calendar quarter 12 months after applicable regulatory approvals	First day of the first calendar quarter 12 months after Board of Trustees adoption
	For supervisory elements as described in PRC-023-2 Attachment A, Section 1.6	First day of the first calendar quarter 24 months after applicable regulatory approvals	First day of the first calendar quarter 24 months after Board of Trustees adoption
	For switch-on-to-fault schemes as described in PRC-023-2 Attachment A, Section 1.3	Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013)	Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011 ¹
	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2

¹ July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
		application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption
	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
~~R4~~	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption
~~R5~~	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption
~~R6~~	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5	First day of the first calendar quarter 18 months after applicable regulatory approvals	First day of the first calendar quarter 18 months after Board of Trustees adoption

First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating² of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
 - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
 - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
 - 115% of the highest emergency rating of the series capacitor.
 - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

² When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
 - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
 - 115% of the highest operator established emergency transformer rating
- 10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability³.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
 - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
 - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature⁴.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
 - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
 - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

³ As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

⁴ IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

- c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in [PRC-023-3](#), Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
 - 6.1 Maintain a list of circuits subject to PRC-023-23 per application of Attachment B, including identification of the first calendar year in which any criterion in [PRC-023-3](#), Attachment B applies.
 - 6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

- M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within [PRC-023-3](#), Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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.~~For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority. For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.~~

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its

Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
<u>3</u>	<u>TBD</u>	<u>Clarify applicability for consistency with PRC-025-1 and other minor corrections</u>	<u>Supplemental SAR (Project 2010-13.2)</u>

PRC-023-~~3~~ — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
 - 1.1. Phase distance.
 - 1.2. Out-of-step tripping.
 - 1.3. Switch-on-to-fault.
 - 1.4. Overcurrent relays.
 - 1.5. Communications aided protection schemes including but not limited to:
 - 1.5.1 Permissive overreach transfer trip (POTT).
 - 1.5.2 Permissive under-reach transfer trip (PUTT).
 - 1.5.3 Directional comparison blocking (DCB).
 - 1.5.4 Directional comparison unblocking (DCUB).
 - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
 2. The following protection systems are excluded from requirements of this standard:
 - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
 - Overcurrent elements that are only enabled during loss of potential conditions.
 - Elements that are only enabled during a loss of communications except as noted in section 1.6
 - 2.2. Protection systems intended for the detection of ground fault conditions.
 - 2.3. Protection systems intended for protection during stable power swings.
 - 2.4. Generator protection relays that are susceptible to load.
 - 2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
 - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
 - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
 - 2.8. Relay elements associated with dc lines.
 - 2.9. Relay elements associated with dc converter transformers.
-

PRC-023-~~3~~ — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses⁵ performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
 - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
 - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
 - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

⁵ Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
 - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
 - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
 - e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.
-

Standard Development Timeline

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

Development Steps Completed

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR was posted for formal comment on August 19, 2010.
3. SAR was revised to add one directive from paragraph P. 224 relating to Phase I on November 1, 2010.
4. SC authorized moving the SAR (Phase II – Generator Relay Loadability) forward to standard development on March 20, 2012.
5. Draft 1 of the standard was posted for a 30-day formal comment period from October 5, 2012 to November 5, 2012.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft ~~4~~2 of PRC-025-1, Generator Relay Loadability for a ~~30~~45-day formal comment period and initial ballot in the last ten days of the comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	October 2012
45-day Formal Comment Period with Parallel Initial Ballot	~~December~~ <u>January</u> 2012
30-day Formal Comment Period with Parallel Successive Ballot	~~March~~ <u>June</u> 2013
Recirculation ballot	~~June~~ <u>July</u> 2013
BOT adoption	August 2013
File with FERC	September 30, 2013 (regulatory directive)

Effective Dates

See PRC-025-1 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

No new or revised term is being proposed.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Generator Relay Loadability
2. **Number:** PRC-025-1

Purpose: To set load-responsive generator protective relays at a level ~~such that to prevent unnecessary tripping of~~ generators ~~do not trip during a system disturbances~~ disturbance for conditions that ~~are~~ do not pose a risk of damaging ~~to~~ the generator ~~thereby unnecessarily removing the generator from service.~~

3. **Applicability:**

3.1. Functional Entities:

3.1.1 Generator Owner that applies load-responsive protective relays ~~on~~ at the terminals of Facilities listed in 3.2, Facilities.

3.2. **Facilities:** The following Elements ~~of the~~ associated with Bulk Electric System ~~generation Facilities~~ generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

3.2.1 Generating unit(s).

3.2.2 Generator step-up (i.e., GSU) transformer(s).

3.2.3 ~~Auxiliary Unit auxiliary~~ transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online.¹

3.2.4 Generator interconnection Facility(ies).

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.²

¹ These transformers are variably referred to as station power, unit auxiliary, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the Guidelines and Technical Basis for more detailed information concerning auxiliary transformers.

² Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (<http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf>)

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

B. Requirements and Measures

R1. Each Generator Owner shall ~~install~~apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay ~~in accordance with PRC-025-1 – Attachment 1: Relay Settings~~, each Generator Owner shall have ~~and provide as evidence, dated documentation (e.g., summaries of: (1) settings calculations, and (2) spreadsheets, simulation reports, or setting sheets)~~ that settings were ~~installed~~applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

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. The Regional Entity shall serve as the Compliance Enforcement Authority (CEA)

~~unless the applicable entity is owned, operated, or controlled by the Regional Entity.~~

1.2. Evidence Retention

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

The Generator Owner 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 Generator Owner shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the ~~latest~~ 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	High	~~To be determined~~ N/A	~~To be determined~~ N/A	~~To be determined~~ N/A	~~To be determined~~ The Generator Owner did not apply settings in accordance with <i>PRC-025-1 – Attachment 1: Relay Settings</i> , on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

NERC System Protection and Control Subcommittee, July 2010, “Power Plant and Transmission System Protection Coordination.”

IEEE C37.102-2006, “Guide for AC Generator Protection.”

PRC-025-1 – Attachment 1: Relay Settings

Introduction

Each Generator Owner that applies load-responsive protective relays on Facilities listed in 3.2, Facilities shall use one of the following Options 1-~~17~~19 in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application. ~~and relay type.~~ The bus voltage is ~~determined by~~based on the criteria for the various applications listed in Table 1.

Synchronous generator ~~output~~relay pickup setting criteria values are ~~determined by~~derived from the unit’s maximum ~~seasonal~~-gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; or Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the ~~rated~~-MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator ~~output~~relay pickup setting criteria values ~~are determined by (including inverter-based installations) are derived from~~ the site’s aggregate maximum ~~seasonal-gross Real Power-complex power~~ capability, in ~~MW~~MVA, as reported to the Planning Coordinator; ~~and the Reactive Power capability, in (Mvar), as determined by calculating the rated Mvars based on the aggregate MVA at rated power factor and adding~~ or Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. ~~Asynchronous~~

Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with no-load tap changers (NLTC). On-load tap changers (OLTC) are rarely used for GSU transformers; when used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU turns ratio may be used.

Any relay elements that are in service only during start up, when the generator is disconnected, or when other Protection System components fail are excluded. Examples include, but are not limited to, the following:

- Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes),
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) provided the distance element is set in accordance with the criteria ~~also include inverter-based installations outlined in the standard,~~
- Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions),

- Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard, or
- Protection systems that are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, and generator interconnection Facilities). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by alternately shading groups of relays within a similar application. Also, intentional buffers were added to the table such that similar options would be paired together on a per page basis. Note that some applications may have additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage ³	Pickup Setting Criteria
Synchronous generators	Phase Distance Relay (21) – Directional toward the Transmission System	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the <u>calculated</u> impedance derived from 115% of: (1) Real Power output – 100% of ~~maximum seasonal gross~~ <u>the MW capability</u> reported to the Planning Coordinator <u>or Transmission Planner</u> , and (2) Reactive Power output – ~~a value that equates to~~ <u>150% of the MW value, derived from the nameplate MVA rating at</u> <u>rated MW power factor</u>
		<u>OR</u>		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the <u>calculated</u> impedance derived from 115% of: (1) Real Power output – 100% of ~~maximum seasonal gross~~ <u>the MW capability</u> reported to the Planning Coordinator <u>or Transmission Planner</u> , and (2) Reactive Power output – ~~a value that equates to~~ <u>150% of the MW value, derived from the nameplate MVA rating at</u> <u>rated MW power factor</u>
		<u>OR</u>		
		3c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the <u>calculated</u> impedance derived from 115% of: (1) Real Power output – 100% of ~~maximum seasonal gross~~ <u>the MW capability</u> reported to the Planning Coordinator <u>or Transmission Planner</u> , and (2) Reactive Power output – ~~a value that equates to~~ <u>100% of the Maximum maximum gross</u> Mvar output determined by simulation

³ Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with no-load tap changers (NLTC). On-load tap changers (OLTC) are rarely used for GSU transformers; when used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio may be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ³	Pickup Setting Criteria
	The same application continues on the next page with a different relay type			
Synchronous generators	Phase Time Overcurrent Relay (51V)-R – voltage-restrained	52a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than <u>115% of</u> the calculated current derived from ~~115% of~~ : (1) Real Power output – 100% of ~~maximum seasonal gross~~ the MW <u>capability</u> reported to the Planning Coordinator <u>or Transmission Planner</u> , and (2) Reactive Power output – ~~a value that equates to~~ 150% of <u>the MW value, derived from the nameplate MVA rating at</u> rated ~~MW~~ <u>power factor</u>
		<u>OR</u>		
		62b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than <u>115% of</u> the calculated current derived from ~~115% of~~ : (1) Real Power output – 100% of ~~maximum seasonal gross~~ the MW <u>capability</u> reported to the Planning Coordinator <u>or Transmission Planner</u> , and (2) Reactive Power output – ~~a value that equates to~~ 150% of <u>the MW value, derived from the nameplate MVA rating at</u> rated ~~MW~~ <u>power factor</u>
		<u>OR</u>		
		72c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than <u>115% o</u> the calculated current derived from ~~115% of~~ : (1) Real Power output – 100% of ~~maximum seasonal gross~~ the MW <u>capability</u> reported to the Planning Coordinator <u>or Transmission Planner</u> , and (2) Reactive Power output – ~~a value that equates to Maximum~~ <u>100% of the maximum gross</u> Mvar output determined by simulation

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage ³	Pickup Setting Criteria
	Phase ~~Time~~ ~~Overcurrent Relay~~ (51C)— ~~time~~ ~~overcurrent relay~~ (51V-C) – voltage ~~controlled~~ (Enabled to operate as a function of voltage (e.g., Voltage controlled relay))	93	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the ~~nominal~~ <u>calculated</u> generator bus voltage
A different application starts on the next page				
Asynchronous generators (including inverter-based installations)	Phase ~~Distance~~ ~~Relay~~ <u>distance relay</u> (21) – ~~D~~ irectional toward the Transmission System	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the <u>calculated</u> impedance, derived from 130% of the ~~total~~ <u>maximum</u> aggregate <u>nameplate</u> MVA output at rated power factor <u>(including the Mvar</u> <u>output of any static or dynamic reactive power devices)</u>
	Phase ~~Time~~ ~~Overcurrent~~ ~~Relay~~ <u>time</u> ~~overcurrent relay~~ (51V)- ~~R~~ – voltage-restrained	85	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than <u>130% of the</u> <u>calculated</u> current, derived from ~~130% of total~~ <u>the maximum</u> aggregate <u>nameplate</u> MVA output at rated power factor <u>(including the Mvar</u> <u>output of any static or dynamic reactive power devices)</u>
	<u>Phase time</u> <u>overcurrent relay</u> (51V-C) – voltage <u>controlled</u> (Enabled to operate as a function of voltage)	6	<u>Generator bus voltage corresponding</u> <u>to 1.0 per unit of the high-side</u> <u>nominal voltage times the turns ratio</u> <u>of the generator step-up transformer</u>	<u>Voltage control setting shall be set less than 75% of the calculated</u> <u>generator bus voltage</u>

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage ³	Pickup Setting Criteria
A different application starts on the next page				
Generator step-up transformer – Synchronous generators	Phase Distance Relay (21) – Directional toward the Transmission System	137a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the <u>calculated</u> impedance derived from 115% of: (1) Real Power output – 100% of ~~connected~~ the aggregate generation MW reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – ~~a value that equates to~~ 150% of ~~connected~~ the aggregate generation MW value, derived from the <u>nameplate MVA rating at rated MW power factor</u>
		OR		
		147b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the <u>calculated</u> impedance derived from 115% of: (1) Real Power output – 100% of ~~connected~~ the aggregate generation MW reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – ~~a value that equates to~~ 150% of ~~rated MW~~ 150% of the aggregate generation MW value, derived from the <u>nameplate MVA rating at rated power factor</u>
		OR		

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage ³	Pickup Setting Criteria
		457c	Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the <u>calculated</u> impedance derived from 115% of: (1) Real Power output – 100% of ~~connected~~ <u>the aggregate</u> generation MW reported <u>to the Planning Coordinator or Transmission Planner</u> , and (2) Reactive Power output – ~~a value that equates to the~~ <u>Maximum 100% of the aggregate generation maximum gross</u> Mvar output determined by simulation
		<u>The same application continues on the next page with a different relay type</u>		
Generator step-up transformer – ~~S~~ synchronous generators	Phase ~~Time~~ <u>Overcurrent</u> Relay ~~time~~ <u>overcurrent relay</u> (51)	8a	<u>Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</u>	<u>The overcurrent element shall be set greater than 115% of the calculated current derived from:</u> (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		<u>OR</u>		
		408b	<u>Calculated generator bus voltage corresponding to 0.85 per unit of the high-side nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</u>	The <u>overcurrent</u> element shall be set greater than <u>115% of</u> the calculated current derived from ~~115% of~~ : (1) Real Power output – 100% of ~~connected~~ <u>the aggregate</u> generation reported <u>to the Planning Coordinator or Transmission Planner</u> , and (2) Reactive Power output – ~~a value that equates to~~ 150% of ~~connected~~ <u>the aggregate</u> generation MW value, derived from the <u>nameplate MVA rating at</u> rated ~~MW~~ power factor

Table 1. Relay Loadability Evaluation Criteria

<u>Application</u>	<u>Relay Type</u>	<u>Option</u>	<u>Bus Voltage³</u>	<u>Pickup Setting Criteria</u>
		<u>OR</u>		
		448c	<u>Simulated generator bus voltage corresponding to 0.85 per unit of the high-side nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</u>	The <u>overcurrent</u> element shall be set greater than <u>115% of</u> the calculated current derived from ~~115% of~~ : (1) Real Power output – 100% of ~~connected~~ <u>the aggregate</u> generation reported <u>to the Planning Coordinator or Transmission Planner</u> , and (2) Reactive Power output – ~~a value that equates to the Maximum~~ <u>100% of the aggregate generation maximum gross</u> Mvar output determined by simulation
		<u>The same application continues on the next page with a different relay type</u>		
Generator step-up transformer – <u>S</u> synchronous generators	<u>Phase directional time overcurrent relay (67) – directional toward the Transmission system</u>	9a	<u>Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</u>	<u>The overcurrent element shall be set greater than 115% of the calculated current derived from:</u> (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the connected generation MW value, derived from the nameplate MVA rating at rated power factor
		<u>OR</u>		
		9b	<u>Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</u>	<u>The overcurrent element shall be set greater than 115% of the calculated current derived from:</u> (1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and (2) Reactive Power output – 150% of the connected generation MW value, derived from the nameplate MVA rating at rated power factor
		<u>OR</u>		

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage ³	Pickup Setting Criteria
		9c	<u>Simulated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</u>	<u>The overcurrent element shall be set greater than 115% of the calculated current derived from:</u> <u>(1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and</u> <u>(2) Reactive Power output –100% of the connected generation maximum gross Mvar output determined by simulation</u>
<u>A different application starts on the next page</u>				
Generator step-up transformer – <u>A</u> synchronous generators only (including inverter-based installations)	Phase ~~Distance~~ <u>distance relay</u> (21) – ~~D~~ irectional toward the Transmission ~~S~~ ystem	~~46~~ <u>10</u>	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the <u>calculated</u> impedance, derived from 130% of the ~~total~~ <u>maximum</u> aggregate <u>nameplate</u> MVA output at rated power factor <u>(including the Mvar output of any static or dynamic reactive power devices)</u>
	Phase <u>Time</u> ~~Overcurrent~~ <u>Relay</u> <u>time overcurrent relay</u> (51)	~~42~~ <u>11a</u>	<u>Generator bus voltage corresponding to 1.0-0.85 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side</u>	The <u>overcurrent</u> element shall be set greater than <u>130% of</u> the calculated current, derived from ~~130% of the maximum~~ aggregate ~~installed maximum rated~~ <u>nameplate</u> MVA output ~~of the connected generators~~ at rated power factor <u>(including the Mvar output of any static or dynamic reactive power devices)</u>
	<u>OR</u>			

Table 1. Relay Loadability Evaluation Criteria

<u>Application</u>	<u>Relay Type</u>	<u>Option</u>	<u>Bus Voltage³</u>	<u>Pickup Setting Criteria</u>	
		<u>11b</u>	<u>1.0 per unit of the high-side nominal voltage for overcurrent relays installed on the high-side</u>	<u>The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)</u>	
	<u>Phase directional time overcurrent relay (67) – directional toward the Transmission system</u>	<u>12</u>	<u>Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</u>	<u>The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)</u>	
<u>A different application starts on the next page</u>					
<u>Auxiliary Unit auxiliary transformers (UAT)</u>	<u>Phase Time Overcurrent Relay time overcurrent relay (51)</u>	<u>13a</u>	1.0 per unit <u>of the winding</u> nominal voltage <u>on the high-side terminals</u> of the <u>unit</u> auxiliary transformer	The <u>overcurrent</u> element shall be set greater than <u>150% of</u> the calculated current derived from <u>150% of the current derived from the unit</u> auxiliary transformer <u>maximum</u> nameplate <u>maximum</u> MVA rating	
		<u>OR</u>			
		<u>13b</u>	<u>Unit auxiliary transformer bus voltage corresponding to the measured current</u>	<u>The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Planning Coordinator or Transmission Planner</u>	
<u>A different application starts below</u>					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ³	Pickup Setting Criteria
<u>Generator interconnection Facilities – synchronous generators</u>	<u>Phase distance relay (21) – directional toward the Transmission system</u>	<u>14a</u>	<u>0.85 per unit of the line nominal voltage</u>	<u>The impedance element shall be set less than the calculated impedance derived from 115% of:</u> <u>(1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and</u> <u>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor</u>
		<u>OR</u>		
		<u>14b</u>	<u>0.85 per unit of the line nominal voltage</u>	<u>The impedance element shall be set less than the calculated impedance derived from 115% of:</u> <u>(1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and</u> <u>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation</u>
	<u>The same application continues on the next page with a different relay type</u>			
<u>Generator interconnection Facilities – synchronous generators</u>	<u>Phase time overcurrent relay (51)</u>	<u>15a</u>	<u>0.85 per unit of the line nominal voltage</u>	<u>The overcurrent element shall be set greater than 115% of the calculated current derived from:</u> <u>(1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and</u> <u>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor</u>
		<u>OR</u>		
	<u>15b</u>	<u>0.85 per unit of the line nominal voltage</u>	<u>The overcurrent element shall be set greater than 115% o the calculated current derived from:</u> <u>(1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and</u> <u>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation</u>	

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ³	Pickup Setting Criteria	
	<u>Phase directional time overcurrent relay (67) – directional toward the Transmission system</u>	<u>16a</u>	<u>0.85 per unit of the line nominal voltage</u>	<u>The overcurrent element shall be set greater than 115% of the calculated current derived from:</u> <u>(1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and</u> <u>(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor</u>	
		<u>OR</u>			
		<u>16b</u>	<u>0.85 per unit of the line nominal voltage</u>	<u>The overcurrent element shall be set greater than 115% of the calculated current derived from:</u> <u>(1) Real Power output – 100% of the aggregate generation reported to the Planning Coordinator or Transmission Planner, and</u> <u>(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output determined by simulation</u>	
<u>A different application starts below</u>					
<u>Generator interconnection Facilities – asynchronous generators only (including inverter-based installations)</u>	<u>Phase distance relay (21) – directional toward the Transmission system</u>	<u>17</u>	<u>1.0 per unit of the line nominal voltage</u>	<u>The impedance element shall be set less than the calculated impedance, derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)</u>	
	<u>Phase time overcurrent relay (51)</u>	<u>18</u>	<u>1.0 per unit of the line nominal voltage</u>	<u>The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)</u>	

Table 1. Relay Loadability Evaluation Criteria

<u>Application</u>	<u>Relay Type</u>	<u>Option</u>	<u>Bus Voltage³</u>	<u>Pickup Setting Criteria</u>
	<u>Phase directional time overcurrent relay (67) – directional toward the Transmission system</u>	<u>19</u>	<u>1.0 per unit of the line nominal voltage</u>	<u>The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)</u>
<u>End of Table 1</u>				

Implementation Plan

Project 2010-13.2 - Relay Loadability: Generator

Requested Approvals

- PRC-025-1 – Generator Relay Loadability

Requested Retirements

- None.

Prerequisite Approvals

- None.

Parallel Approvals

- PRC-023-3 – Transmission Relay Loadability*

*A supplemental SAR was approved by the Standards Committee at the January 16-17, 2013 meeting to authorize the drafting team to make corresponding changes to PRC-023-2 in order to establish a bright line between the applicability of load-responsive protective relays in the transmission and generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The implementation plan addresses concerns about the effort required to become compliant with the standard. The drafting team considered a number of issues that a Generator Owner might encounter in its efforts to ensure its load-responsive protective relay settings are applied in accordance the standard. The period to become compliant is based on two conditions. One time frame is provided if the Generator Owner determines that its existing load-responsive protective relays are capable of achieving the standard while maintaining reliable fault protection. A second and extended time frame is provided if the Generator Owner determines that its existing load-responsive protective relays require replacement. The drafting team recognizes that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment.

General Considerations

The Implementation Plan period reflects consideration of the following:

- ~~1. The Generator Owner will likely find it necessary to adjust the existing load responsive protective relay settings on its generation unit(s) to comply with this standard, and it will be necessary for the plant to be off-line in order to make these adjustments.~~
- ~~2. The Generator Owner may find it necessary to replace portions of their existing protective relaying in order to comply with this standard. In such cases, the Generator Owner may need to budget the necessary work, engineer the necessary adjustments, coordinate with other entities, and procure certain materials. Further, the Generator Owner may require an outage of significant duration in order to apply settings, perform necessary testing, and replace any necessary components.~~
1. It is not beneficial to reliability for a Generator Owner to remove a generation unit or plant from service solely to achieve compliance with this standard.
- ~~3.1. The Additionally, the implementation plan recognizes that the time between scheduled outages depends on the nature of the generation unit or plant and may be as long as 24 months. Due to the time between scheduled outages, the implementation plan also considers the time required to budget and procure the necessary material; therefore, provides a 48-month period for becoming 100% compliant with the standard.~~
- ~~4. The For a Generator Owner with a sizable generation fleet, the implementation plan assumes that Generator Owners will stagger provides time for staggered outages between generation units or plants.~~

General Considerations

~~To be developed in draft 2 based upon fleet size, operating history, and forecasted outages on industry comment.~~

- ~~2. The Generator Owner will need to evaluate load-responsive protective relays applied on its Facilities, perform the applicable calculations required by the standard, and determine whether existing relays are capable of meeting the performance of standard while achieving reliable fault protection.~~
- ~~3. It is necessary for the generation unit or plant to be off-line in order to make adjustments.~~
- ~~4. The outage duration in order to replace any necessary components, to apply settings, and perform necessary testing may be significant.~~
- ~~5. For those load-responsive protective relays that do not require replacement, the Generator Owner will need time to complete the evaluation (#4) required by the standard and schedule the work while the generation unit or plant is off-line.~~

6. For those load-responsive protective relays that require replacement, the Generator Owner will need time to complete the evaluation (#4) required by the standard, as well as, time to coordinate protection system changes with other entities, procure materials, and schedule the work while the generation unit or plant is off-line.

Applicable Entities

- Generator Owner*

*See the proposed standard for detailed applicability for functional entities and Facilities.

Effective Date

New Standard

PRC-025-1 First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

None. N/A

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-025-1, Requirement R1

Load -responsive protective relays subject to the standard

~~Each~~The Generator Owner that owns load-responsive protective relays applicable to this standard shall be 100% compliant for the following: 48 months beyond the effective date of this standard.

- For each load-responsive protective relay, where determined by the Generator Owner that replacement is not necessary, 48 months beyond the effective date of this standard.
- For each load-responsive protective relay, where determined by the Generator Owner that replacement is necessary, 72 months beyond the effective date of this standard.

Load -responsive protective relays which become applicable to the standard

The Generator Owner ~~owning that owns~~ load-responsive protective relays that become applicable to this standard, ~~(not~~ because of the actions of the Generator Owner including, but not limited to changes in NERC Registration Criteria, Bulk Electric System (BES) definition, or any other non-Generator Owner action~~),~~ shall be 100% compliant on the first day of the first calendar quarter that is 48 months beyond the date such change is effected by an applicable regulatory authority, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be retired or revised when this standard is implemented. If the drafting team is recommending the retirement or revision of a requirement, that text is blue.

Already Approved Standard	Proposed Replacement Requirement(s)
New Standard – Not Applicable	PRC-025-1 R1. Each Generator Owner shall ~~apply~~<u>install</u> settings that are in accordance with <i>PRC-025-1 – Attachment 1: Relay Settings</i>, on each load-responsive protective relay while maintaining reliable <u>fault</u> protection. <i>[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]</i>
Notes: This requirement meets the directive in <u>FERC</u> Order No. 733, paragraph <u>106 and supporting paragraphs 104, 105, and 108</u>. <u>A full discussion of how Requirement R1 is responsive to the FERC directives may be found in the Consideration of Issues and Directives document associated with Project 2012-13.2 – Relay Loadability: Generator</u>~~102~~.	

Violation Risk Factor and Violation Severity Level Justifications

PRC-025-1 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Relay Loadability: Generator.

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.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL 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. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

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

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.

- 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 – 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.

Violation severity levels should be based on the guidelines shown in the table below:

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 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 and VSL Justifications

VRF Justifications – PRC-025-1, R1	
Proposed VRF	High
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-1, Attachment 1; Relay Settings, 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. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a “High” VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a “High” VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-1, R1	
Proposed VRF	High
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-1, R1				
R1	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Generator Owner did not apply settings in accordance with PRC-025-1 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

VSL Justifications – PRC-025-1, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Currently, there is no compliance obligation related to the subject of this standard; therefore there is no current level of compliance which would lead to lowering the current level of compliance.

Proposed VSLs for PRC-025-1, R1	
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 single proposed VSL is a binary VSL (pass-fail). The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be “Severe” in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is 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 addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on “an applied load-responsive protective relay” in accordance with Attachment 1: Relay Settings.

Project 2010-13.2 Generator Relay Loadability

Consideration of Issues and Directives

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	Source	Consideration of Issue or Directive
NERC Ref: S-10724 Para 106 supported by Paragraphs 104, 105, and 108. 106. We also expect that the ERO will develop the Reliability Standard addressing generator relay loadability as a new Standard, with its own individual timeline, and not as a revision to an existing Standard. While we agree that PRC-001-1 requires, among other things, the coordination of generator and transmission protection systems, we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability Standard if it is not to be addressed with transmission relay loadability. Para 104, 105, and 108 104. We decline to adopt the NOPR proposal and will not direct the ERO to modify PRC-023-1 to address	Order No. 733 (Para 104, 105, 106, and 108)	Response to P106 The Reliability Standard PRC-025-1 is responsive to paragraph 106 by establishing a new standard that addresses generator unit relay loadability for load-responsive protective relays applicable to generators for the conditions (depressed voltages) observed during the August 2003 blackout in the northeastern portion of North America. Response to P104 The Reliability Standard PRC-025-1 is responsive to paragraph 104 by establishing requirements for load-responsive protective relays on generator step-up (GSU) transformers and on unit auxiliary transformers (UAT) that supply station service power to support the on-line

Project 2010-13.2 Generator Relay Loadability

Issue or Directive	Source	Consideration of Issue or Directive
generator step-up and auxiliary transformer loadability. After further consideration, we conclude that it does not matter if generator step-up and auxiliary transformer loadability is addressed in a separate Reliability Standard, so long as the ERO addresses the issue in a timely manner and in a way that is coordinated with the Requirements and expected outcomes of PRC-023-1. 105. In light of the EROs statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard. While we recognize that generator relay loadability is a complex issue that presents different challenges than transmission relay loadability, we note that more than six years have passed since the August 2003 blackout and there is still no Reliability Standard that addresses generator relay loadability. With this in mind, the Commission will not hesitate to direct the development of a new Reliability Standard if the ERO fails to propose a Standard in a timely manner. While the ERO is developing a		operation of generating plants. These transformers are variably referred to as station power, unit auxiliary, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. The standard is coordinated with the expected outcomes of PRC-023-2 in that it will assure that the applicable equipment will not be removed from service unnecessarily for the conditions observed during the August 2003 blackout in the northeastern portion of North America. Response to P105 The Reliability Standard PRC-025-1 is responsive to paragraph 105 by developing a new standard to address generator relay loadability according to the filed schedule. This Phase II of relay loadability required an extension of time to complete, extending the deadline to September 30, 2013. A one year extension was granted on February 15, 2012, Docket No. RM08-13-001. Response to P108 The Reliability Standard PRC-025-1 is responsive to

Project 2010-13.2 Generator Relay Loadability

Issue or Directive	Source	Consideration of Issue or Directive
technical reference document to facilitate the development of a Reliability Standard for generator protection systems, only Reliability Standards create enforceable obligations under section 215 of the FPA. 108. Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.		paragraph 108 by establishing a requirement for each Generator Owner to apply settings on its load-responsive protective relays for generator step-up transformers (including, generator units and unit auxiliary transformers). For generator step-up (GSU) transformers connected to synchronous generator units, the standard implements Attachment 1: Relay Settings to the standard and Table 1 which establishes settings based on a percentage of the generator unit's maximum gross Real Power capability in megawatts (MW), as reported to the Planning Coordinator and Transmission Planner; and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar). For generator step-up (GSU) transformers connected to synchronous generator units, the standard implements Attachment 1: Relay Settings to the standard and Table 1 which establishes settings based on a percentage of the generator unit's aggregate installed maximum rated MVA output (including the Mvar output of any static or dynamic reactive power devices) of the connected generators at rated power factor. Asynchronous generator criteria also include inverter-based

Project 2010-13.2 Generator Relay Loadability		
Issue or Directive	Source	Consideration of Issue or Directive
		installations. Unit auxiliary transformers unit auxiliary transformers (UAT) that supply station service power to support the on-line operation of generating plants are based on a percentage of the MVA rating of the transformers or the auxiliary loads at the rated MW as reported to the Planning Coordinator or Transmission Planner. These transformers are variably referred to as station power, unit auxiliary, or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running.

Standard Authorization Request Form

Supplemental SAR for Project 2010-13.2 Relay Loadability Order 733 Phase 2 (Relay Loadability: Generation)

Request Date 11/30/2012

SC Approval Date 01/18/2013

Revised Date

SAR Requester Information	SAR Type (Check a box for each one that applies.)	
Name Howard Gugel, Director of Standards Development	☐	New Standard
Primary Contact Scott Barfield-McGinnis, Standards Developer	☒	Revision to existing Standard
Telephone 404-446-9689 Fax	☐	Withdrawal of existing Standard
E-mail scott.barfield@nerc.net	☐	Urgent Action

Purpose

Prevent a potential compliance overlap with the current Reliability Standard PRC-023-2 – Transmission Relay Loadability, which became effective July 1, 2012. The overlap would be created when the proposed PRC-025-1 – Generator Relay Loadability, which is currently under development, is approved and becomes effective.

Industry Need

The generator relay loadability standard drafting team identified conditions in the development of the drafting of the PRC-025-1 standard that would create the potential for overlap (e.g., “double jeopardy”) and confusion as to which standard is applicable to the Generator Owner entity (i.e., PRC-023-2 or PRC-025-1).

Brief Description

This request includes modifying PRC-023-2 to add clarity to the Applicability section of the PRC-023-2 standard. Other modifications include updating references from the version number to reflect the new version number. Detail regarding the effective dates may be removed as the new version is anticipated to become approved beyond the implementation plan for the current version.

Detailed Description

The generator relay loadability standard drafting team (GENRLOS DT) continues to evaluate the best alternative to modifying PRC-023-2 to clarify the Generator Owner’s applicability with regard to load-responsive protective relays. The drafting team has provided a redline draft to PRC-023-2 with a proposed solution to the issue; however, the drafting team recognizes that the draft PRC-025-1 may provide the opportunity to remove the Generator Owner from PRC-023-2 and therefore eliminate the overlap and confusion without creating a gap in reliability.

The drafting team considered whether changes would be necessary to Requirement R1, criterion 6 and decided it should remain in the standard as there may be cases where PRC-023 will be applicable to lines that connect generation stations remote to load. The drafting team has not revealed any concerns about this criterion in relation to the proposed PRC-025-1 standard currently being drafted.

The effective date of the draft PRC-023-3 is anticipated to occur beyond the Implementation Plan approved in version two; therefore, the effective date tables are proposed for removal. If an interim implementation is required to bridge PRC-023-2 to the next version, the standard drafting team will modify the effective date tables accordingly.

A complete review of the standard will be conducted to reveal any editorial edits that may be needed to improve the quality of the Reliability Standard.

Industry commenting, balloting, and approval of the revisions to the draft PRC-023-3 standard will occur contemporaneously with the drafting of the proposed PRC-025-1 standard. Adoption of PRC-023-3 will be contingent upon PRC-025-1.

Reliability Functions

The Standard will Apply to the Following Functions <i>(Check box for each one that applies.)</i>		
☐	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 its portion of the Planning Coordinator's Area.
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	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.
☐	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 <i>(Check box for all that apply.)</i>	
☒	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? <i>(Select 'yes' or 'no' from the drop-down box.)</i>	
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Related Standards

Standard No.	Explanation
None.	

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Title: **Rapid Revision Procedure**

Purpose: This document presents a procedure, permitted by the Standard Processes Manual (SPM), to develop a limited and narrowly defined revision to a reliability standard. It is intended that this procedure will accelerate the development and approval of narrow revisions, while ensuring consistent application and better transparency to the industry regarding use of the procedure.

Conditions: When the following conditions are met:

1. requirement(s) or other component(s) of an approved reliability standard is(are) determined to be unclear,
2. the lack of clarity or an incorrect interpretation could result in incorrect or inconsistent implementation of the requirement(s),
3. a determination is made that Interpretation is not possible without revision of the standard language,
4. the revision to the standard that would resolve the lack of clarity is narrow in scope, and
5. the proposal is to revise a standard whose scope is judged to be simple and straight-forward,

then this Rapid Revision Procedure may be used in lieu of including the issue within the scope of a Standard Authorization Request (SAR) governing a normal standards project.

Responsibility	Activity
NERC Standards Staff	Review the issue and prepare a recommendation to the Standards Committee regarding whether the request should move forward as a Rapid Revision. If the recommendation is to proceed with Rapid Revision, and the submitter has not previously presented a SAR, prepare a draft SAR for limited and narrowly defined revision(s) to the standard and put together a recommended slate of 5-7 nominees for appointment to the Rapid Revision Drafting Team, considering the following: • If the proposed revision is associated with a standard recently developed, solicit volunteers from the Standard Drafting Team that developed the standard. • If appropriate, seek nominations for a new team through NERC's technical committees and other industry groups, or through the usual nomination process.

NERC Standards Staff	Submit the request and any associated slate of nominees for the Rapid Revision Drafting Team with a recommendation to the Standards Committee.
Standards Committee	Review the draft SAR and accept or decline NERC staff's recommendation to proceed with Rapid Revision. If proceeding with the Rapid Revision, appoint a Rapid Revision Drafting Team.
NERC Standards Staff	Have a project number assigned and a web page developed with the request and the drafting team roster posted. Appoint a Standards Developer to facilitate the drafting team in developing a SAR and proposed revision to the standard. Seek input from the compliance department to assist the drafting team in identifying compliance-related issue(s) that need resolution. Forward this information to the coordinator/advisor assigned to the project. Appoint any other members as needed to support the team with regulatory and technical writing expertise and to incorporate quality review into the drafting.
Standards Developer	Review issues database and Compliance Application Notices (CANs) for related issues. Provide related issues to drafting team.
Standards Developer	Organize and facilitate a meeting (may be done during a conference call) with the drafting team to refine the SAR and proposed revision to the standard if necessary, and develop the implementation plan, comment form, and project schedule.
Rapid Revision Drafting Team	Refine the SAR and proposed revision to the standard for posting (if necessary), and develop the implementation plan, comment form, possible changes to the Reliability Audit Standard Worksheet (RS AW) and project schedule.
Standards Developer	Work with technical writer, legal, and compliance staff assigned to support the project to finalize documents for posting and ensure that documents meet quality review criteria. Submit the finalized work products to the Manager of Standards Information for posting.

NERC Standards Staff	At the next scheduled Standards Committee or Standards Committee's Executive Committee meeting/conference call, seek authorization to post the SAR and proposed revisions to the standard for a parallel 45-day formal comment period and initial ballot, with ballot pool formation during the first 30 days of the comment period.
NERC Standards Staff	Post the SAR and proposed revisions for a 45-day comment period with the formation of a ballot pool during the first 30 days and an initial ballot during the last 10 days of that 45-day period. (Only conduct a non-binding poll if there are modifications to Violation Risk Factors or Violation Severity Levels.) Ensure the announcements for the comment period and the ballot, as well as the introduction to the comment form, clarify the narrow focus of the team's work and clarify that the team is not working to address other aspects of the standard.
NERC Standards Staff	Assemble comments submitted and distribute to the Rapid Revision Drafting Team.
Rapid Revision Drafting Team	Review and respond to all comments. If the comments result in non-substantive changes (or no changes) to the proposed revisions, submit the response to comments and any conforming changes to the standard and its implementation plan to the Manager of Standards Information for posting for a recirculation ballot. If the comments (or the results of the ballot) do not indicate consensus for the proposed revisions: Consider whether to proceed to a successive ballot, or refer back to the Standards Committee for possible alternative actions.
NERC Standards Staff	If the comments indicate consensus for the proposed revisions, announce and conduct a recirculation ballot for 10 calendar days. If the comments do not indicate consensus for the proposed revisions, announce that the revisions needed are more significant than originally envisioned, announce and conduct a successive ballot, or notify the Standards Committee and provide a recommendation for next steps. Send a notice of the status/outcome to the requester.

Standards Announcement

Rapid Revision Procedure

Informal Comment Period: February 5 – March 6, 2013

[Now Available](#)

A 30-day informal comment period is now open for the Rapid Revision Procedure, which formalizes a process for developing limited and narrowly defined revisions to a standard in cases where it has been determined that an Interpretation is not an option within existing standard language.

The document was developed by a working group comprised of Standards Committee Process Subcommittee members and approved for posting by the Standards Committee on October 11, 2012. It was created to formalize the process explored in the pilot projects, and has been posted for comment to ensure process transparency and consistent application.

Instructions for Commenting

An informal comment period for the Rapid Revision Procedure is open through **8 p.m. Eastern on Wednesday, March 6, 2013**. Please use this [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the [project page](#).

Next Steps

A Standards Committee Process Subcommittee working group will review the comments and, if necessary, make corresponding changes to the procedure document. If substantive changes are made, another informal comment period may be required. The procedure document will then be presented to the Standards Committee for approval.

Background

The Rapid Revision Procedure was developed to address focused situations where it has been determined that a request for Interpretation was best addressed by limited and narrowly defined revisions to a standard. It accelerates the development of narrow revisions while adhering to the Standard Processes Manual: A Standard Authorization Request is still required, but it is posted alongside limited, focused, and narrowly defined revisions to the standard and implementation plan. Ultimately, the goal is to have only one 45-day comment and ballot period and then proceed to a final recirculation ballot.

Three pilot projects – Interpretation 2010-INT-01 Rapid Revision of TOP-006-2 for FMPP, Project 2011-INT-02 Rapid Revision of VAR-002 to address Constellation Request for Interpretation, and Revision of MOD-

028-1 to address FPL Request for Interpretation – employed the rapid revision process and required only six to 12 months to earn Board of Trustees approval, less than the average timeline for a traditional standards project.

The procedure document formalizes the process explored in the pilot projects, and has been posted for comment ensure process transparency and consistent application. Additional information is available on the [project page](#).

Standards Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Standards Announcement

Project 2012-INT-06 – Interpretation of CIP-003-3 for Consumers Energy

Formal Comment Period Open: February 6 – March 22, 2013

Ballot Pool Forming Now: February 6 – March 7, 2013

Upcoming

Initial Ballot: March 13 – March 22, 2013

Now Available

A formal comment period for an interpretation of **CIP-003-3** for Consumers Energy is open through **8 p.m. Eastern on Friday, March 22, 2013**. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Thursday, March 7, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

Instructions for Joining Ballot Pool(s)

Registered Ballot Body members must join the ballot pool to be eligible to vote in the balloting of the interpretation of CIP-003-3. Registered Ballot Body members may join the ballot pool at the following page: [Join Ballot Pool](#)

During the pre-ballot window, members of the ballot pool may communicate with one another by using the “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.)

The ballot pool list server for this ballot pool is: bp-2012-INT-06_CIP-003_in@nerc.com

The ballot pool is open **through 8 a.m. Eastern on Thursday, March 7, 2013**.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Friday, March 22, 2013**. Please use the [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the [project page](#).

Next Steps

An initial ballot will be conducted March 13, 2013 through 8 p.m. ET Friday, March 22, 2013.

Background

In May 2011, the Standards Committee appointed a standing CIP Interpretation Drafting Team for the development of CIP Interpretations. A project team from the CIP Interpretation Drafting Team has reviewed Consumers request for interpretation and developed this interpretation pursuant to the NERC Guidelines for Interpretation Drafting Teams. Consumers Energy requested clarification on Section 4.1 of CIP-003-3 Requirement R2 as to if a registered entity can assign different CIP Senior Managers for different applicable functions it is registered for.

Standards Development Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact, Monica Benson
Standards Development Administrator, at Monica.Benson@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

A. Introduction

1. **Title:** Cyber Security — Security Management Controls
2. **Number:** CIP-003-3
3. **Purpose:** Standard CIP-003-3 requires that Responsible Entities have minimum security management controls in place to protect Critical Cyber Assets. Standard CIP-003-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.
4. **Applicability:**
 - 4.1. Within the text of Standard CIP-003-3, “Responsible Entity” shall mean:
 - 4.1.1 Reliability Coordinator.
 - 4.1.2 Balancing Authority.
 - 4.1.3 Interchange Authority.
 - 4.1.4 Transmission Service Provider.
 - 4.1.5 Transmission Owner.
 - 4.1.6 Transmission Operator.
 - 4.1.7 Generator Owner.
 - 4.1.8 Generator Operator.
 - 4.1.9 Load Serving Entity.
 - 4.1.10 NERC.
 - 4.1.11 Regional Entity.
 - 4.2. The following are exempt from Standard CIP-003-3:
 - 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
 - 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
 - 4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets shall only be required to comply with CIP-003-3 Requirement R2.
5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

- R1. Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management’s commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:
 - R1.1. The cyber security policy addresses the requirements in Standards CIP-002-3 through CIP-009-3, including provision for emergency situations.

- R1.2.** The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.
 - R1.3.** Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.
- R2.** Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-3 through CIP-009-3.
 - R2.1.** The senior manager shall be identified by name, title, and date of designation.
 - R2.2.** Changes to the senior manager must be documented within thirty calendar days of the effective date.
 - R2.3.** Where allowed by Standards CIP-002-3 through CIP-009-3, the senior manager may delegate authority for specific actions to a named delegate or delegates. These delegations shall be documented in the same manner as R2.1 and R2.2, and approved by the senior manager.
 - R2.4.** The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.
- R3.** Exceptions — Instances where the Responsible Entity cannot conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).
 - R3.1.** Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).
 - R3.2.** Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures.
 - R3.3.** Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.
- R4.** Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.
 - R4.1.** The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002-3, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.
 - R4.2.** The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.
 - R4.3.** The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.
- R5.** Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.
 - R5.1.** The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.
 - R5.1.1.** Personnel shall be identified by name, title, and the information for which they are responsible for authorizing access.

- R5.1.2.** The list of personnel responsible for authorizing access to protected information shall be verified at least annually.
- R5.2.** The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.
- R5.3.** The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.
- R6.** Change Control and Configuration Management — The Responsible Entity shall establish and document a process of change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.

C. Measures

- M1.** The Responsible Entity shall make available documentation of its cyber security policy as specified in Requirement R1. Additionally, the Responsible Entity shall demonstrate that the cyber security policy is available as specified in Requirement R1.2.
- M2.** The Responsible Entity shall make available documentation of the assignment of, and changes to, its leadership as specified in Requirement R2.
- M3.** The Responsible Entity shall make available documentation of the exceptions, as specified in Requirement R3.
- M4.** The Responsible Entity shall make available documentation of its information protection program as specified in Requirement R4.
- M5.** The Responsible Entity shall make available its access control documentation as specified in Requirement R5.
- M6.** The Responsible Entity shall make available its change control and configuration management documentation as specified in Requirement R6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits
Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Requirement R2 applies to all Responsible Entities, including Responsible Entities which have no Critical Cyber Assets. Modified the personnel identification information requirements in R5.1.1 to include name, title, and the information for which they are responsible for authorizing access (removed the business phone information). Changed compliance monitor to Compliance Enforcement Authority.	
3		Update version number from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update

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

When completed, email this form to:
laura.hussey@nerc.net
For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

Response to a Request for an Interpretation of a Reliability Standard CIP-003-3 for Consumers Energy

Date submitted: June 9, 2011

Contact information for person requesting the interpretation:

Name: Jeanne M. Kurzynowski

Organization: Consumers Energy Company

Telephone: (517)788-1110

E-mail: jmkurzyn@cmsenergy.com

Identify the standard that needs clarification:

Standard Number (include version number, e.g. PRC-001-1): CIP-003-3

Standard Title: Cyber Security – Security Management Controls

Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement: R2. Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity's implementation of, and adherence to, Standards CIP-002-3 through CIP-009-3.

Identify the nature of clarification that is requested: (Check as many as applicable)

- ☐ Clarify the required performance
- ☐ Clarify the conditions under which the performance is required
- ☒ Clarify which functional entity is responsible for performing an action in a requirement
- ☐ Clarify the reliability outcome the requirement is intended to produce

Please explain the clarification needed: Section 4.1 of CIP-003-3, "Applicability" specifies that a "Responsible Entity" shall mean...", and lists several functions. If one substitutes any of these functions for the term "Responsible Entity", it would appear that there could be a different Senior Manager for each function to which that entity is registered. With regard to CIP-003-3,

R2 can a Registered Entity assign different CIP Senior Managers for different applicable functions for which it is registered? (If so, a Registered Entity could have more than one CIP senior manager, but each Responsible Entity would have a single CIP senior manager.)

Identify the material impact associated with this interpretation:

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

An incorrect interpretation of the standard may impact an organization's CIP compliance structure.

Question

Consumers Energy Corporation seeks clarification on the meaning of CIP-003-3, Requirement R3 as it relates to designating a CIP Senior Manager.

In its response, the Interpretation Drafting Team will answer whether a Registered Entity may assign different CIP Senior Managers for different applicable functions for which it is registered.

Response

~~No, a Registered Entity cannot assign different CIP Senior Managers for different applicable functions for which it is registered.~~ A Registered Entity cannot assign different CIP Senior Managers for different applicable functions if those functions are included under one registration (NERC ID).

Organizational Registration is a process defined in the NERC Rules of Procedure undertaken by NERC and Regional Entities to identify which entities are responsible for reliability functions within the Regional Entity's Region. Within the NERC Rules of Procedure a "Registered Entity" means an owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, that is included in the NERC Compliance Registry. The Rules of Procedure further clarify that a "Responsible Entity" means an entity that is registered for a reliability function in the NERC Compliance Registry and is responsible for complying with an Applicable Requirement, as specified in the "Applicability" section of the CIP Standard.

The number of NERC CIP Senior Managers depends on how the entity registers and appears in the Compliance Registry. Each Registered Entity, even if registered as performing multiple registration functions, shall assign a single CIP Senior Manager. If a single company has multiple Registered Entities (i.e. company has registered one business segment as a GO/GOP, and another business segment registered as TO/TOP) it could assign a CIP Senior Manager to each Registered Entity, but that would not preclude the entity from assigning a single senior manager to both Registered Entities. Similarly, if the same single company has only one NERC ID, i.e. the entity is registered once for its GO/GOP and TO/TOP collectively, the entity assigns one CIP Senior Manager.

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

When completed, email this form to:

laura.hussey@nerc.net

For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

Request for an Interpretation of a Reliability Standard	
Date submitted: June 9, 2011	
Contact information for person requesting the interpretation:	
Name:	Jeanne M. Kurzynowski
Organization:	Consumers Energy Company
Telephone:	(517)788-1110
E-mail:	jmkurzyn@cmsenergy.com
Identify the standard that needs clarification:	
Standard Number (include version number, e.g. PRC-001-1): CIP-003-3	
Standard Title: Cyber Security – Security Management Controls	
Identify specifically what requirement needs clarification:	
Requirement Number and Text of Requirement: R2. Leadership — The Responsible Entity shall assign a single senior manager with overall responsibility and authority for leading and managing the entity’s implementation of, and adherence to, Standards CIP-002-3 through CIP-009-3.	
Identify the nature of clarification that is requested: (Check as many as applicable)	
☐ Clarify the required performance ☐ Clarify the conditions under which the performance is required ☒ Clarify which functional entity is responsible for performing an action in a requirement ☐ Clarify the reliability outcome the requirement is intended to produce	
Please explain the clarification needed: Section 4.1 of CIP-003-3, “Applicability” specifies that a “Responsible Entity” shall mean...”, and lists several functions. If one substitutes any of these functions for the term “Responsible Entity”, it would appear that there could be a different Senior Manager for each function to which that entity is registered. With regard to CIP-003-3, R2 can a Registered Entity assign different CIP Senior Managers for different applicable	

functions for which it is registered? (If so, a Registered Entity could have more than one CIP senior manager, but each Responsible Entity would have a single CIP senior manager.)

Identify the material impact associated with this interpretation:

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

An incorrect interpretation of the standard may impact an organization's CIP compliance structure.

Standards Announcement

Project 2012-INT-04 – Interpretation of CIP-007-3 for ITC

Formal Comment Period Open: February 6 – March 22, 2013

Ballot Pool Forming Now: February 6 – March 7, 2013

Upcoming

Initial Ballot: March 13 – March 22, 2013

Now Available

A formal comment period for an interpretation of **CIP-007-3** for ITC is open through **8 p.m. Eastern on Friday, March 22, 2013**. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Thursday, March 7, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

Instructions for Joining Ballot Pool(s)

Registered Ballot Body members must join the ballot pool to be eligible to vote in the balloting of the interpretation of CIP-007-3. Registered Ballot Body members may join the ballot pool at the following page: [Join Ballot Pool](#)

During the pre-ballot window, members of the ballot pool may communicate with one another by using the “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.)

The ballot pool list server for this ballot pool is: [bp-2012-INT-04_CIP-007- in@nerc.com](mailto:bp-2012-INT-04_CIP-007-in@nerc.com)

The ballot pool is open **through 8 a.m. Eastern on Thursday, March 7, 2013**.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Friday, March 22, 2013**. Please use the [electronic form](#) to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the [project page](#).

Next Steps

An initial ballot will be conducted March 13, 2013 through 8 p.m. ET Friday, March 22, 2013.

Background

In May 2011, the Standards Committee appointed a standing CIP Interpretation Drafting Team (IDT) for the development of CIP Interpretations. A project team from the CIP IDT has reviewed ITC's request for interpretation and developed this interpretation pursuant to the NERC Guidelines for IDTs. In its first question, ITC asked for clarification on whether each sub-requirement of CIP-007-3, Requirement R5 requires both "technical and procedural controls." In its second question, ITC asked for clarification on whether technical controls in CIP-007-3, Requirement R5.3 mean that each individual Cyber Asset within the Electronic Security Perimeter (ESP) has to automatically enforce each of the three R5.3 sub-parts.

Standards Development Process

The [Standard Processes Manual](#) contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance, please contact, Monica Benson
Standards Development Administrator, at Monica.Benson@nerc.net or at 404-446-2560.*

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

A. Introduction

1. **Title:** Cyber Security — Systems Security Management
2. **Number:** CIP-007-3
3. **Purpose:** Standard CIP-007-3 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.
4. **Applicability:**
 - 4.1. Within the text of Standard CIP-007-3, “Responsible Entity” shall mean:
 - 4.1.1 Reliability Coordinator.
 - 4.1.2 Balancing Authority.
 - 4.1.3 Interchange Authority.
 - 4.1.4 Transmission Service Provider.
 - 4.1.5 Transmission Owner.
 - 4.1.6 Transmission Operator.
 - 4.1.7 Generator Owner.
 - 4.1.8 Generator Operator.
 - 4.1.9 Load Serving Entity.
 - 4.1.10 NERC.
 - 4.1.11 Regional Entity.
 - 4.2. The following are exempt from Standard CIP-007-3:
 - 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
 - 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
 - 4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.
5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

- R1. Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007-3, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.
 - R1.1. The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.

- R1.2.** The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.
 - R1.3.** The Responsible Entity shall document test results.
- R2.** Ports and Services — The Responsible Entity shall establish, document and implement a process to ensure that only those ports and services required for normal and emergency operations are enabled.
 - R2.1.** The Responsible Entity shall enable only those ports and services required for normal and emergency operations.
 - R2.2.** The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).
 - R2.3.** In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.
- R3.** Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003-3 Requirement R6, shall establish, document and implement a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).
 - R3.1.** The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.
 - R3.2.** The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.
- R4.** Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software (“malware”) prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware on all Cyber Assets within the Electronic Security Perimeter(s).
 - R4.1.** The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure.
 - R4.2.** The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention “signatures.” The process must address testing and installing the signatures.
- R5.** Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.
 - R5.1.** The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of “need to know” with respect to work functions performed.
 - R5.1.1.** The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.

- R5.1.2.** The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.
 - R5.1.3.** The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.
 - R5.2.** The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.
 - R5.2.1.** The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.
 - R5.2.2.** The Responsible Entity shall identify those individuals with access to shared accounts.
 - R5.2.3.** Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).
 - R5.3.** At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:
 - R5.3.1.** Each password shall be a minimum of six characters.
 - R5.3.2.** Each password shall consist of a combination of alpha, numeric, and “special” characters.
 - R5.3.3.** Each password shall be changed at least annually, or more frequently based on risk.
- R6.** Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.
 - R6.1.** The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.
 - R6.2.** The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.
 - R6.3.** The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008-3.
 - R6.4.** The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.
 - R6.5.** The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.
- R7.** Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-3.

- R7.1.** Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.
- R7.2.** Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.
- R7.3.** The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.
- R8.** Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:
 - R8.1.** A document identifying the vulnerability assessment process;
 - R8.2.** A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;
 - R8.3.** A review of controls for default accounts; and,
 - R8.4.** Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.
- R9.** Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007-3 at least annually. Changes resulting from modifications to the systems or controls shall be documented within thirty calendar days of the change being completed.

C. Measures

- M1.** The Responsible Entity shall make available documentation of its security test procedures as specified in Requirement R1.
- M2.** The Responsible Entity shall make available documentation as specified in Requirement R2.
- M3.** The Responsible Entity shall make available documentation and records of its security patch management program, as specified in Requirement R3.
- M4.** The Responsible Entity shall make available documentation and records of its malicious software prevention program as specified in Requirement R4.
- M5.** The Responsible Entity shall make available documentation and records of its account management program as specified in Requirement R5.
- M6.** The Responsible Entity shall make available documentation and records of its security status monitoring program as specified in Requirement R6.
- M7.** The Responsible Entity shall make available documentation and records of its program for the disposal or redeployment of Cyber Assets as specified in Requirement R7.
- M8.** The Responsible Entity shall make available documentation and records of its annual vulnerability assessment of all Cyber Assets within the Electronic Security Perimeters(s) as specified in Requirement R8.
- M9.** The Responsible Entity shall make available documentation and records demonstrating the review and update as specified in Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- 1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2 ERO for Regional Entity.
- 1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting
Complaints

1.4. Data Retention

- 1.4.1 The Responsible Entity shall keep all documentation and records from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- 1.4.2 The Responsible Entity shall retain security-related system event logs for ninety calendar days, unless longer retention is required pursuant to Standard CIP-008-3 Requirement R2.
- 1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment and acceptance of risk. Revised the Purpose of this standard to clarify that Standard CIP-007-2 requires Responsible Entities to define methods, processes, and procedures for securing Cyber Assets and other (non-Critical)	

		Assets within an Electronic Security Perimeter. Replaced the RRO with the RE as a responsible entity. Reworking of Effective Date. R9 changed ninety (90) days to thirty (30) days Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version numbers from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	

When completed, email this form to:
maureen.long@nerc.net
For questions about this form or for assistance in
completing the form, call Maureen Long at 813-468-5998.

Note: an Interpretation cannot be used to change a standard.

Response to a Request for an Interpretation of a Reliability Standard CIP-007-3 for ITC Transmission

Date submitted: 12-28-2011

Contact information for person requesting the interpretation:

Name: Charles Lewis

Organization: ITC Transmission

Telephone: 248-946-3182

E-mail: clewis@itctransco.com

Identify the standard that needs clarification:

Standard Number (include version number): CIP-007-3

(example: PRC-001-1)

Standard Title: Cyber Security – Systems Security Management

Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

R5. Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.

R5.3. At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:

R5.3.1. Each password shall be a minimum of six characters.

R5.3.2. Each password shall consist of a combination of alpha, numeric, and “special” characters.

R5.3.3. Each password shall be changed at least annually, or more frequently based on risk.

Clarification needed:

ITC respectfully requests an interpretation regarding the following:

1. Does each sub-requirement, including R5.3, of R5 require that both "technical and procedural controls" be utilized?
2. Do "technical controls", utilized in the context of R5.3, mean that each individual cyber asset device within an ESP has to automatically enforce each of the three R5.3 sub-requirements? The three bullets below are part of this question; they are examples if this is interpreted to be true.
 - R5.3.1. Each password shall be a minimum of six characters. Each individual cyber asset device within an ESP has to automatically reject any password that does not conform to a minimum of six characters.
 - R5.3.2. Each password shall consist of a combination of alpha, numeric, and "special" characters. Each individual cyber asset device within an ESP has to automatically reject any password that does not conform to a combination of alpha, numeric and "special" characters.
 - R5.3.3. Each password shall be changed at least annually, or more frequently based on risk. Each individual cyber asset device within an ESP has to automatically force passwords to be changed at least annually or at a specified interval based on risk.

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard.

If it is interpreted that R5.3 requires "technical controls" that automatically enforce password requirements, then there will be a need for entities to file a significant number of additional TFEs. The majority of devices used in the industry, while allowing passwords that meet all of the R5.3 sub-requirements, are not able to automatically enforce the requirements of R5.3.1, R5.3.2 and R5.3.3. In addition, it is expected the TFEs submitted for this requirement will have to be kept in place for a long period of time until device manufacturers create products that can enforce R5.3.1, R5.3.2 and R5.3.3.

A correct interpretation is needed for entities to determine whether existing cyber assets within ESPs are fully compliant with this requirement to avoid penalties associated with noncompliance.

Question

ITC Transmission seeks clarification on the meaning of CIP-007-3, Requirement R5 as it relates

to both technical and procedural controls.

In its response, the Interpretation Drafting Team will answer:

1. Whether each sub-requirement of R5 requires both “technical and procedural controls.”
2. Whether technical controls in Requirement R5.3 mean that each individual Cyber Asset within the Electronic Security Perimeter (ESP) has to automatically enforce each of the three R5.3 sub-requirements.

Response

Question 1: Does each sub-requirement of Requirement R5 require use of both “technical and procedural controls”?

No, it is not necessary for both technical and procedural controls to be used in each sub-requirement of Requirement R5. The use of “and” in Requirement R5 indicates that the responsible entity must implement both technical and procedural controls to achieve collectively the sub-requirements within Requirement R5 and the associated sub-requirements. Both are not necessary for each sub-requirement individually.

Generally, technical controls are carried out or managed by computer systems. That is distinct from a technical aspect that enables or confirms procedural enforcement. While it is possible to have a technical component, tool, or aspect for each procedural control, mere use of technology to enable or support a procedural control is not necessarily a technical control itself. If a control relies on ongoing human intervention, then it is generally a procedural control. Procedural controls are the actions that people take, and they are the process of developing and ensuring compliance with policy and procedures. The responsible entity must look at what’s performing the control to determine whether it’s technical or procedural: the control is accomplished either by a human being using technology (procedural) or a computer managing or performing the control (technical). The IDT also notes that regardless of control type (technical or procedural) the entity has the compliance requirement of implementing the control and demonstrating evidence of the control.

Question 2: Does the use of “technical controls” in Requirement R5.3 mean that each individual Cyber Asset within the Electronic Security Perimeter (ESP) has to automatically enforce each of the three R5.3 sub-requirements.

No, the IDT interprets the three sub-requirements within R5.3 no differently than the other sub-requirements of R5, ~~with the exception of the technical feasibility exception (TFE) capability provided under R5.3.~~ As requested under the request for interpretation, the concept of automatically enforcing controls is viewed by the IDT as the need to enforce the combination of the technical and procedural controls that are implemented to ~~achieve strict compliance~~ satisfy the three sub-requirements of R5.3. The automatic enforcement component ~~would~~ could apply to the technical controls that are implemented, however most procedural controls are not automatic. The IDT interprets that the responsible entity would need to demonstrate that controls have been put in place to ~~achieve strict compliance with~~ satisfy the three sub-

requirements of R5.3. ~~In the case where a specific device is not capable of implementing either a technical or procedural control, the entity would file for TFE treatment.~~

When completed, email this form to:

maureen.long@nerc.net

For questions about this form or for assistance in completing the form, call Maureen Long at 813-468-5998.

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard
Date submitted: 12-28-2011
Contact information for person requesting the interpretation:
Name: Charles Lewis
Organization: ITC Transmission
Telephone: 248-946-3182
E-mail: clewis@itctransco.com
Identify the standard that needs clarification:
Standard Number (include version number): CIP-007-3 (example: PRC-001-1)
Standard Title: Cyber Security — Systems Security Management
Identify specifically what requirement needs clarification:
Requirement Number and Text of Requirement: R5. Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access. R5.3. At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible: R5.3.1. Each password shall be a minimum of six characters. R5.3.2. Each password shall consist of a combination of alpha, numeric, and “special” characters. R5.3.3. Each password shall be changed at least annually, or more frequently based on risk.

Clarification needed:

ITC respectfully requests an interpretation regarding the following:

1. Does each sub-requirement, including R5.3, of R5 require that both "technical and procedural controls" be utilized?
2. Do "technical controls", utilized in the context of R5.3, mean that each individual cyber asset device within an ESP has to automatically enforce each of the three R5.3 sub-requirements? The three bullets below are part of this question; they are examples if this is interpreted to be true.
 - R5.3.1. Each password shall be a minimum of six characters. Each individual cyber asset device within an ESP has to automatically reject any password that does not conform to a minimum of six characters.
 - R5.3.2. Each password shall consist of a combination of alpha, numeric, and "special" characters. Each individual cyber asset device within an ESP has to automatically reject any password that does not conform to a combination of alpha, numeric and "special" characters.
 - R5.3.3. Each password shall be changed at least annually, or more frequently based on risk. Each individual cyber asset device within an ESP has to automatically force passwords to be changed at least annually or at a specified interval based on risk.

Identify the material impact associated with this interpretation:

Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard.

If it is interpreted that R5.3 requires "technical controls" that automatically enforce password requirements, then there will be a need for entities to file a significant number of additional TFEs. The majority of devices used in the industry, while allowing passwords that meet all of the R5.3 sub-requirements, are not able to automatically enforce the requirements of R5.3.1, R5.3.2 and R5.3.3. In addition, it is expected the TFEs submitted for this requirement will have to be kept in place for a long period of time until device manufacturers create products that can enforce R5.3.1, R5.3.2 and R5.3.3.

A correct interpretation is needed for entities to determine whether existing cyber assets within ESPs are fully compliant with this requirement to avoid penalties associated with noncompliance.