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

NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #16-5
October 5, 2016 10:00 a.m. – 5:00 p.m. EST
October 6, 2016 8:00 a.m. – 3:00 p.m. EST
NYPA Niagara Power Project Power Vista Visitor Center
5777 Lewiston Road
Lewiston, New York
Attire: Business Casual

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

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

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes

3.0 Drafting Team Members and Executive Tracking Summary

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

4.0 Open Action Items

4.1 Open Action Items List

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
5.2 RSC Scope of Work
5.3 RSC Work Plan
5.4 GMD FERC Order
5.5 IRO-018-1/TOP-010-1 FERC Order
5.6 NPCC Regional Feedback Mechanism Process
5.7 NPCC CC Process for Submitting Implementation Guidance
5.8 Project 2016-03 Cyber Security Supply Chain Management

6.0 NERC Reliability Standards

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

6.1 Currently Posted Projects

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

6.2 Ballot History (Since last RSC Meeting)

6.3 Comment Form History (Since last RSC Meeting)

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies

7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation For Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

8.1.1 FERC Approved the Retirement of PRC-002-NPCC-01

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

8.1.3 Approval of Final Draft PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance for 45-day comment period posting

8.1.4 Geomagnetic Disturbance Mitigation TPL-007-1 Quebec Variance

9.0 NPCC Non-Standards

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

9.1 Directories:

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

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

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

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

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

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

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

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

9.1.8 Criteria Clarifications;

- Directory#4 *System Protection Criteria* (Pending Request for Clarification—TFSP)
- Directory#5 *Reserve* – (TFCO Clarification RCC Approved September 7th, 2016).
- Directory#1 *Design and Operation of the BPS* – (TFCP Clarification RCC Approved September 7th, 2016)

10.0 RSC Member Items of Interest

10.1 RSC Roster

11.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

11.1 NERC Filings to FERC
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.2 FERC Orders / Rules
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.3 Federal Register
https://www.federalregister.gov/
11.4 FERC Sunshine Act Meeting Notice
11.5 FERC Open Meeting Summaries

12.0 NERC Meetings

12.1 Standards Committee (SC)
http://www.nerc.com/comm/SC/Pages/default.aspx

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

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

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

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

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

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

13.0 NERC Items of Interest (Since last RSC Meeting)

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

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

13.2 Alerts

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

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

13.3 Second Draft of 2017 Business Plan and Budget

13.4 Standard Committee 2017 Meeting Schedule

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

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

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

14.2 NPCC Board of Directors Meeting (BOD) 2016

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

14.3 NPCC Board of Directors Meeting (BOD) 2017

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

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2016 Meeting Dates

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

RSC 2017 Meeting Date

15.2 RSC 2016 Conference Call Schedule (calls can be schedule as needed) all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 28840965)

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

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

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

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NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #16-4
August 10, 2016 10:00 a.m. – 5:00 p.m. EST
August 11, 2016 8:00 a.m. – 3:00 p.m. EST
IESO Office
120 Adelaide St West 16th Floor
Toronto, Ontario M5H 1T1
Attire: Business Casual

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

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated June 24, 2016
NPCC Glossary of Terms, dated January 14, 2014

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Guy Zito	Northeast Power Coordinating Council		1 & 2	
2.	Gerry Dunbar	Northeast Power Coordinating Council		1 & 2	
3.	Ruida Shu	Northeast Power Coordinating Council		1 & 2	
4.	Juan Villar	FERC	Guest	1 & 2	
5.	Howard Gugel	NERC	Guest	1	
6.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1 & 2	
7	Michael Jones	National Grid	3	1 & 2	
8.	Brian Shanahan	National Grid	1	1 & 2	Via Phone
9.	Joel Charlebois	AESI, Inc.	Guest	1 & 2	
10.	Kelly Silver	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1 & 2	
11.	David Ramkalawan	Ontario Power Generation, Inc.	4	1 & 2	
12.	David Kwan	Ontario Power Generation, Inc.	4	1 & 2	
13.	Chantal Mazza	Hydro-Québec TransÉnergie	2	1 & 2	
14.	Helen Lainis	IESO	2	1 & 2	
15.	Navneet Singh	IESO	Guest	1 & 2	

16.	Jim Grant	New York Independent System Operator	2	1 & 2	
17.	Payam Farahbakhsh	Hydro One Networks	1	1	
18.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1 & 2	
19.	Quintin Lee	Eversource Energy	1	1 & 2	
20.	Laura Mcleod	New Brunswick Power Corporation	1	1 & 2	
21.	Brian Robinson	Utility Services, Inc.	5	1 & 2	
22.	David Kiguel	Independent	Guest	1 & 2	
23.	Damase Hebert	Northeast Power Coordinating Council		1	
24.	Salvatore Spagnolo	New York Power Authority	4	1 & 2	
25.	Michael Puscas	ISO-NE	2	1 & 2	Via Phone
26.	Sean Bodkin	Dominion Resources Services	4	1 & 2	Via Phone
27.	Ron Falsetti	AESI	Guest	1 & 2	Via Phone
28.	Michele Tondalo	The United Illuminating Company		1	Via Phone
29.	Mark Olson	NERC	Guest	1	Via Phone
30.	Laura Anderson	NERC	Guest	1	Via Phone
31.	Al McMeekin	NERC	Guest	1	Via Phone
32.	Jordan Mallory	NERC	Guest	1	Via Phone
33.	Lauren Perotti	NERC	Guest	1	Via Phone
34.	Lacey Ourso	NERC	Guest	1	Via Phone
35.	Mat Bunch	NERC	Guest	1	Via Phone

Introductions and Chair's Remarks
Guy Zito opened the meeting by welcoming the RSC to Toronto. He mentioned that Bruce Metruck will be retiring from NYPA and relinquishing his post as Co-Vice Chairperson of the RSC. Guy Zito asked RSC Members to consider self-nominations to replace Bruce Metruck as Co-Vice Chairperson and to forward any self-nomination to Gerry Dunbar of the RSC.
Ruida Shu indicated that the quorum has been reached for the RSC meeting.

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

Agenda Items:

1.0 Review of Agenda

Guy Zito reviewed the agenda with the members of RSC.
Agenda moved forward by unanimous consent.

2.0 RSC Meeting Minutes

Approval of Minutes—there was one minor grammar revision to the Final Meeting Minutes of 6-22-16.
Michael Jones made a motion for approval.
Jim Grant seconded the motion.
Ben Wu and Brian Robinson abstained.
The Meeting Minutes were approved as revised and documented.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams

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

3.2 Executive Tracking Summary

Gerry Dunbar will provide the Directory and Criteria update as part of agenda 9.0.

3.3 NERC Project Tracking Spreadsheet

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

4.0 Open Action Items

4.1 Open Action Items List

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin

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

5.2 NPCC Regional Feedback Mechanism Process

Damase Hebert called in at 10AM and provided a presentation on the proposed NPCC Regional Feedback Mechanism Process.

The feedback process is intended to document how a standard improvement issue is identified, evaluated and addressed. The process will route issues to the appropriate NERC Standard Development Process (SAR, RSAR, Variance, E.P.R.).

RSC Members discussed whether the process was a vehicle for compliance or reliability or both.

Damase Hebert will incorporate comments received and have another draft circulated by August 17th.

Damase Hebert would like the final version of the draft endorsed by the RSC at the October meeting in order to formally implement the process by the end of 2016.
Howard Gugel indicated that as an ERO we are actively pushing for more feedback mechanism processes. Other regions are at various stages of developing similar feedback mechanisms. The tracking mechanism should be promoted. The process is targeted to capture more consensus issues.
The NPCC Regional Feedback Mechanism Process is not intended to be used as an appeal process.
This process can potentially be used as inputs for Standards Grading.

5.3 Functional Model Version 6

Guy Zito provided an update on the Functional Model Advisory Group. (FMAG)

The Functional Model Technical Document has been revised and is currently posted for comment through September 6th, 2016.

The FMAG reports to the Standards Committee and works with the Planning Committee, the Operating Committee and CIPC to obtain consensus regarding proposed changes.

Many of the changes to the FM are aimed at providing clarity surrounding the planning functions (Planning Authority, Planning Coordinator, Transmission Planner). However certain changes to the Transmission Operator function have the potential to drive a registration change.

5.4 Cost Effectiveness Pilot

Guy Zito provided a status report of the pilot of the Cost of Risk Reduction Analysis "CRRA" also referred to as a Cost Effectiveness analysis. The Pilot is being conducted on the Single Point of failure Project 2015-10, TPL-001-4. A comment period closed and a report is being developed which will be posted shortly. The Pilot was conducted and focused strictly on two FERC Directives: consideration of outages of less than 6 months in duration in planning studies and consideration of long lead time items to correct potential stability related issues. The Pilot posed two multipart questions regarding cost and risks associated with the Directives. The second part of the pilot, yet to be conducted anticipates gathering more detailed cost information once the standard is revised and prior to its final ballot.

Action Item: Ruida Shu will forward the phase one report to the RSC members when it is posted.

5.5 SPS-RAS NPCC Transition

Gerry Dunbar provided a presentation on the proposed regional transition from Special Protection Systems (SPS) to Remedial Action Schemes (RAS).

RAS definition approved November 19th, 2015 and NERC has effectively retired the term SPS in the NERC Glossary.

The term SPS, in the NERC Glossary, will become inactive on 3/31/2017.

RAS will become effective on 4/1/2017.

Proposed transition process includes three phases: I) TFSS to establish a RAS list from the existing SPS list ii) review all NPCC documents containing the term SPS iii) Pending approval of PRC -012-2 review SPS criteria in Directory #7.

TFCP will provide coordination and oversight of the transition consistent with its role in approving new or modified SPS's.

There are 105 SPS(s)/RAS(s) in NPCC region and there are 83 type III SPS(s)/RAS(s).

5.6 PRC-025-1 Generator Loadability

Eric Loiselle from Hydro Quebec called in at 11AM and presented PRC-025-1 Generator Loadability issue from Hydro Quebec.

Eric Loiselle presented technical data to demonstrate that certain aspects of the standards requirements were not simultaneously feasible for HQT because of the long generator transmission lines employed on the HQT system.

The RSC discussed various solutions to the HQT issues including I) application guidance ii) SAR iii) Enhanced Periodic Review.

Howard Gugel of NERC suggested contacting the NERC Standard developer working on the EPR team in order to provide input to him so these concerns may be considered in the project to revise the standard's requirements.
Action Item: Ruida Shu will send this HQ PRC-025-1 Generator Loadability issue to Scott Barfield to ensure the standard drafting team include this as part of the tasks.

5.7 FERC Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities

Guy Zito notified the RSC that FERC recently issued a Final Order requiring entities with Small Generator Interconnection Pro-forma agreements filed with the Commission to revise those agreements to require small generating facilities to provide the same ride through capability for voltage and frequency currently required of larger generators.

5.8 Project 2016-03 Cyber Security Supply Chain Management

Guy Zito provided a presentation on CIP Supply Chain Management.
FERC Order issued on July 21st, 2016 to develop a new or modified standard that addresses supply chain risk management for hardware, software and computing and networking services associated with BES operations.
NERC to submit industry approved standard to the BOT by August 2017 (within one year of the effective date of the Final Rule).
The Standard Committee has approved solicitation of SDT nominations through August 18th, 2016.

5.9 NPCC Compliance Guidance Policy – Implementation Guidance

Guy Zito provided background on the NERC Compliance Guidance Policy. The policy features two components: I) Implementation Guidance ii) ERO Practice Guides.
The NPCC Compliance Committee is a Regional Entity Stakeholder Committee and is pre-qualified to vet examples proposed for Implementation Guidance in accordance with the NERC Compliance Guidance Policy.
The CC is currently developing a process for submitting this Implementation Guidance to NERC.
The RSC considered what role they had in providing input to the CC when developing Implementation Guidance.
Herb Schrayshuen noted that the RSC has within its scope a provision that supports RSC engagement in NERC Compliance Guidance Development Policy. Herb Schrayshuen also noted that the currently proposed CC approach only covers guidance developed from within NPCC and does not cover the topic of how NPCC will prepare comments on draft guidance submitted by others within the NERC process. Also, the CC process should be more open and recognize that the CC may not have expertise in all functional areas of utility operations. All registered entities including NPCC Task Forces should have input into the process.
These comments were forwarded to Mr. Hebert and any additional comments should be submitted to the CC by August 26th, 2016.

5.10 2016 Risk Profiles

Guy Zito provided an update on the 2016 Risk Profiles.

The profiles are developed by the RISC (Reliability Issues Steering Committee) and identify, define and prioritize reliability risks to the BPS including evolving reliability risks.

6.0 NERC Reliability Standards

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

6.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date	Standards Developer	8/10/16 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation Revisions to Project White Papers	6/13/16 (I)	NA	Mark Olson	1:00PM
Enhanced Periodic Review Standing Review Team - Standards Grading	8/1/16 (I)		Mat Bunch	1:15PM
Project 2015-10 Single Points of Failure TPL-001	6/24/16 (I)	SAR	Jordan Mallory	1:30PM
Project 2016-01 Modifications to TOP and IRO Standards	8/3/16 (F)	8/3/16 (I)	Mark Olson	1:45PM
Project 2016-02 Modifications to CIP Standards	9/6/16 (F)	9/6/16 (I)	Al McMeekin Stephen Crutchfield	2:00PM
Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	9/12/16 (F)	9/12/16 (I)	Al McMeekin Stephen Crutchfield	2:00PM
Revisions to the NERC Standard Processes Manual	10/28/15 (I)	NA	Lauren Perotti	2:15PM
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)	NA	Lacey Ourso	2:30PM
Project 2015-08 Emergency Operations EOP-004-4	9/8/16 (F)	9/8/16 (I)	Sean Cavote Laura Anderson	2:45PM
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

Project 2013-03:
Mark Olson called into the RSC meeting at 1:00PM.
The TPL-007 standard is filed and pending regulatory approval.
The drafting team members discovered an error in a white paper submitted to support the standards technical development. This error was corrected and the revised white paper was posted for industry comment which has delayed FERC action on the filing.
The revised white paper has a new graph to show a 75A per phase benchmark GMD test for transformer thermal ratings.
75A per phase benchmark is used as a conservative threshold.

Standard Grading:
Mat Bunch called into the RSC meeting at 1:15PM.
The standard grading team is composed of the Chairs of the OC, PC, CIPC and a regional representative (Guy Zito).
The standard requirement grades developed by the team were posted for industry comment which concluded on August 1, 2016.
Second public meeting is on August 30, 2016.

The Standard Grading effort is intended to review the requirements for technical/quality content. The final grade of the standard grading effort will go into the 2017-2019 Reliability Standards Development Plan and Standard Committee will evaluate and determine the priority.

Project 2015-10:
Jordan Mallory called into the RSC meeting at 1:28PM.
Modifications have been recommended to Reliability TPL-001-4.
The System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) conducted a comprehensive assessment of the study of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for data or information.
The SAR was accepted by the SC on July 22, 2016.
The SC approved posting the SAR and is currently seeking nominations for the standard drafting team.

Project 2016-01:
Mark Olson called back into the RSC meeting at 1:34PM.
The goal of this project is to address the FERC directives contained in Order 817 by modifying TOP-001-3 and IRO-002-4 or developing an equally efficient and effective alternative.
Initial ballot was closed on August 3, 2016 and the ballot failed.
Among the issues identified were:
Lack of clarity regarding the need to monitor non-BES facilities.
Diverse routing can potentially cause a compliance issue if you have a component data exchange failure and there is no redundant.
monthly testing is not necessary and the standard drafting team is considering alternate testing period. (Quarterly testing period is suggested.)

Project 2016-02:
Al McMeekin called into the RSC meeting at 1:47PM.
The SDT clarified the definition of LERC (Low Impact External Communication) and the LEAP definition will be retired.
The definition is posted from July 21, 2016 to September 6, 2016.
The next meeting of the SDT will be on August 16, 2016 in Rosemead CA and there will be a public webinar on August 16, 2016 to review the project status.
The SDT is divided into 5 sub-teams. (LERC Definition, Definitions and Concepts, TO Control Centers/Communication Networks, Virtualization and TD at lows)
Industry wants more specificity on Virtualization.
Virtualization can potentially impact various existing NERC definitions such as Cyber Asset, Virtual Cyber Asset or Virtual Machine etc.
The goal is post the draft documents by December 2016 with all the changes from each sub-teams.
ERC (External Routable Connectivity) is one of the definition being reviewed by the SDT.

Project 2015-INT-01:
Al McMeekin provided a brief discussion on the Project 2016-INT-01.

Energy Sector Security Consortium (EnergySec) requested an interpretation seeking clarification regarding the use of the phrase “shared BES Cyber Systems.”
The SDT has provided a response to all three questions contained in the interpretation request from EnergySec.

Revisions to the NERC Standard Processes Manual:
Lauren Perotti called into the RSC meeting at 2:15PM.
Appendix 3 to the Rules of Procedure, revisions are being done in section 6, 7 and 11.
Section 6 is a field test which allows the Standard Committee stop a field test.
The goal is to clarify the document.
Section 7 is the interpretation process document.
The goal is to ensure interpretations are being done on a timely basis.
Section 11 revisions are underway.
The plan is to finalize all the changes by end of the year.

Project 2015-09:
Lacey Ourso called into the RSC meeting at 2:22PM.
The Project includes, FAC-010, FAC-011 and FAC-014.
Possible revisions to the definition of IRO.
The webinar recording is posted on the Project page.
The next SDT in person meeting will be on August 22, 2016 at California ISO.
FAC-011 and FAC-014 comments are due on August 12, 2016.

Project 2015-08 EOP-004-4:
Laura Anderson called into the RSC meeting at 2:35PM.
EOP-004-4 is currently posted for comments.
The SDT is proposing several revisions to clarify duplicate reporting.
The Event Analysis group provided their comments to the SDT during a scheduled conference call.
The SDT is trying to work with Department of Energy to coordinate reporting requirements between E0P-004-4 and the OE-417 the reporting requirements.
There is a scheduled webinar on August 18, 2016.

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

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

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies
7.1.1 Project 2015-10 Single Points of Failure – TPL-001 SDT

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)
7.2.1 None at this time

7.3 Solicitation for Informal Development Teams
7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

8.1.1 Disturbance Monitoring Standard PRC-002-NPCC-01 status update.

Ruida Shu provided an update: joint petition to retire the Regional Standard was filed by NERC and NPCC. Update: FERC approved the retirement of PRC -002-NPCC-01 effective August 16th, 2016.

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

Ruida Shu provided an update: Drafting Team has conducted one meeting.

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

Ruida Shu provided an update: revisions to Quebec Variance currently posted for comment. Approval process will be conducted in accordance with the NPCC RSPM.

8.1.4 Geomagnetic Disturbance Mitigation TPL-007-1 Quebec Variance

Guy Zito provided an update: NERC recently completed revisions to a white paper as part of the development package for TPL-007-1. Guy Zito stated its likely that FERC will issue directives in its Final Rule which will require revisions to the standard. Guy Zito suggested that the HQT concerns can be addressed as part of the SAR developed to address the directives

9.0 NPCC Non-Standards

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

Gerry Dunbar updated the RSC on the status of the following:

9.1 Directories:

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

TFCO and the CO11 Working Group revised the Directory and posted to receive comments. Additional revisions to the criteria based on comments received have been incorporated and TFCO anticipates posting Directory#8 to the Open Process for a 2nd posting after its August meeting.

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

TFCO and its CO7 ad hoc Working Group have recommended retiring Directories #9 and #10 upon the full enforcement of MOD-25-2 on July 1st, 2019. The retirement recommendation was posted to the Open Process and TFCO will consider comments received at its August meeting.

9.1.3 Directory#7 *SPS* and NPCC Glossary term SPS - TFSP to consider impact of BOT Approved PRC-012-2 *Remedial Action Schemes* and FERC approved RAS definition.

See RAS Transition Agenda item 5.5.

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

TFCP will undertake a review of the A-10 methodology in 2016. TFCP anticipates assigning this review to the CP11 *Working Group on Review of NPCC Basic Criteria* and is currently considering the scope of such a review prior to formally assigning it to the CP11.

9.1.5 Directory#11 *Disturbance Monitoring Equipment Criteria* – (status of TFSP review).

Initial draft of Directory#11 was posted to the Open Process and TFSP has reviewed comments received. Comment revisions were non substantive and Directory#11 will be presented to the RCC in September.

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

TFCP posted the A-01 to the Open Process to receive comments through August 12th. TFCP will consider comments.

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

Pending TFCO and CO8 review.

9.1.8 Criteria Clarifications;

- Directory#5 *Reserve* – (status of TFCO Clarification).
- Directory#1 *Design and Operation of the BPS* – (status of TFCO Clarification.)

Both Criteria Clarifications as rendered by the TFCO and TFCP were posted to the Open Process. The Task Forces considered all comments and both Clarifications will be presented to the RCC for final approval in September.

10.0 RSC Member Items of Interest

10.1 RSC Roster

The RSC Members reviewed the current RSC roster for changes.
David Kwan from OPG is added to the roster.

11.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

11.1 NERC Filings to FERC
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.2 FERC Orders / Rules
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.3 Federal Register
https://www.federalregister.gov/

11.4 FERC Sunshine Act Meeting Notice

11.5 FERC Open Meeting Summaries

12.0 NERC Meetings

12.1 Standards Committee (SC)
http://www.nerc.com/comm/SC/Pages/default.aspx

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

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

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

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

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

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

13.0 NERC Items of Interest (Since last RSC Meeting)

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

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

13.2 Alerts

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

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

13.3 Second Draft of 2017 Business Plan and Budget

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

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

14.2 NPCC Board of Directors Meeting (BOD) 2016

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

14.3 NPCC Business Plan and Budget 2017

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2016 Meeting Dates

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

15.2 RSC 2016 Conference Call Schedule (calls can be schedule as needed) all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 28840965)

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

The meeting is adjourned at 10:43AM.

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

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

NPCC Representatives on NERC Standards Drafting Teams

Project No.	Project Title	DT Type	NPCC Representatives	Company	Telephone	E-mail Address
2007-06	Phase 1: System Protection Coordination	Standard	None			
2007-06.2	Phase 2: System Protection Coordination	Standard	Ruida Shu Po Bun Ear	NPCC Hydro-Quebec TransEnergie	917-934-7976	rshu@npcc.org ear.po-bun@hydro.qc.c
2007-17.4	PRC-005 FERC Order No. 803 Directive	Standard				
2009-02	Real-time Monitoring and Analysis Capabilities	Standard	T.J. (Tim) Kucey	PSEG Fossil, LLC		Timothy.Kucey@pseg.com
2009-03	Emergency Operations	Standard	Connie Lowe	Dominion Resource Services, Inc.	804-819-2917	connie.lowe@dom.com
2010-05.2	Remedial Action Schemes (Phase 3 of Protection Systems)	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard				
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard				
2010-14.2.2	Periodic Review of BAL Standards - BAL-004	Standard				
2013-03	Geomagnetic Disturbance Mitigation	Standard	Emanuel Bernabeu	PJM	804-432-8780	emanuel.e.bernabeu@dom.com
			Kenneth Fleischer	NextEra Energy	561-691-2456	kenneth.fleischer@fpl.com
			Luis Marti	Hydro One Networks	416-345-5317	luis.marti@hydroone.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure)	Standard	Jill Loewer	Utility Services		jill.loewer@utilitysvcs.com
2015-06	Interconnection Reliability Operations and Coordination - IRO-006-East and IRO-009	Standard				
2015-08	Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008	Standard	Connie Lowe Karen Backmen	Dominion IESO	804-819-2917	connie.lowe@dom.com Karen.backmen@ieso.ca
2015-09	Establish and Communicate System Operating Limits - FAC-010, FAC-011, FAC-014	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
2015-10	Single Points of Failure - TPL-001	Standard	Ovidiu Vasilachi Rich Kowalski	IESO Observer ISO-NE		
2016-01	Modifications to TOP and IRO Standards - TOP-001, IRO-002	Standard	Steve Brain Philippe Labrosse	Dominion Resource Services, Inc. Hydro-Quebec TransEnergie		
2016-03	Cyber Security Supply Chain Management	Standard	Norm Dang David Bryan Gayle	IESO Dominion Resource Services, Inc.		
2016-04	Modifications to PRC-025-1	Standard				

Source = NERC Standard Drafting Team Rosters - September 2016

Projects Added:

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

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

NPCC Regional Reliability Standards Executive Tracking Summary

Revised: **9/4/2015**

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

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

x

Acronyms:

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

NPCC Document Open Process Executive Tracking Summary

Revised: **9/29/2016**

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

Line No.	Type	Document	Description	Latest Revision	Comments	Status
1	Criteria	A-01	Criteria for Review and Approval of Documents	Mar-05	TFCP Posted for Comment. Comment Period Ends 8/12/2016.	TFCP Reviewing in Accordance with NRAP. TFCP Currently Considering Comments and Potential Revisions in Advance of a 2nd Posting.
2	Criteria	A-10	Classification of BPS Elements	Dec-09	TFCP to Review in 2016.	TFCP Developing Scope of Review---CP11 Review to Commence late 2016.
3	Criteria	A-15	Disturbance Monitoring Equipment Criteria	Aug-07	To be Retired Pending Development of D#11.	Retirement Pending Directory#11 Approval----D#11 RCC Approved--Pending Full Member Ballot.
4	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System	Feb-13		
5	Guideline	B-12	Guidelines for On Line Computer System Performance During Disturbances	Nov-07		
6	Guideline	B-25	Guide to Time Synchronization Substation Equipment	Nov-08		Incorporated into Draft Directory#11 (Appendix A)
7	Guideline	B-26	Guide for Application of Disturbance Recording Equipement	Sep-06		Incorporated into Draft Directory#11 (Appendix B)
8	Guideline	B-27	Regional Critical Asset Identification Methodology	Feb-08	TFIST Retirement Recommendation.	B-27 Retired 6/01/2016.
9	Guideline	B-28	Guide for Generator Sequence of Events Monitoring	Feb-12		Incorporated into Draft Directory#11 (Appendix C)
10	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures	Jun-16		TFCO Completed Update June 2016.
11	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems	Jun-16		TFCO Completed Update June 2016.
12	Procedure	C-25	Procedure to Collect Power System Event Data	Sep-07		TFSS to Review and Update for Inclusion in D#11or Potential Retirement.
13	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings	Mar-07	TFSS Revisions.	TFSS Evaluating Comments from Recent Open Process. SS37 to Provide Recommendation on Retirement.
14	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations	Dec-09	TFSP Retirement Recommendation.	C-30 Retired 6/01/2016.
15	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems	Apr-06		
16	Procedure	C-35	NPCC Power System Restoration Guideline	Mar-16		CO11 Currently Reviewing.
17	Procedure	C-39	Procedure to Collect Major Disturbance Event Data	Dec-09	TFSP Retirement Recommendation.	C-39 Retired 6/01/2016.
18	Procedure	C-43	NPCC Operational Review for the Integration of New facilities	Aug-08		
19	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	Nov-14		Comment Period Concluded on July 23, 2016. TFSP to Consider Comments.

NPCC Directory Executive Tracking Summary

Revised: 9/29/2016 Further details regarding the individual documents may be found at:

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

NPCC Directory Criteria Clarifications

Revised: **9/29/2016** Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/Directory%20Interpretations/Forms/Public%20List.aspx

Line No.	Document	Title of Directory	Date Final	Task Force Review	Posted Open Process?	RCC Approval	Comments	Status
1	Directory #8 Interpretation	System Restoration	6/18/2012	TFCO	N/A	N/A	Interpretation on behalf of the NYSRC	Complete
2	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	8/28/2012	TFSP	N/A	N/A	Interpretation on behalf of Bangor Hydro	Complete
3	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	12/14/2012	TFSP	N/A	N/A	Interpretation on behalf of Con Ed	Complete
4	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	2/15/2013	TFSP	N/A	N/A	Response Clarified - Interpretation on behalf of Acumen Engineered Solutions	Complete
5	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	10/25/2013	TFSP	N/A	N/A	Interpretation on behalf of Hydro One Networks	Complete
6	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	3/4/2015	TFSP	Yes on October 16th, 2014.	Yes	Interpretation on behalf of IESO-MACD	Complete.
7	Directory#8 Clarification	System Restoration	12/1/2015	TFCO	Yes on June 6th, 2015.	Yes	Clarification on Behalf of OPG.	Complete.
8	Directory#5 Clarification	Reserve	9/7/2016	TFCO	Posting Completed July 28th, 2016	Yes	Clarification on Behalf of the NYISO.	Complete

9/29/2016

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

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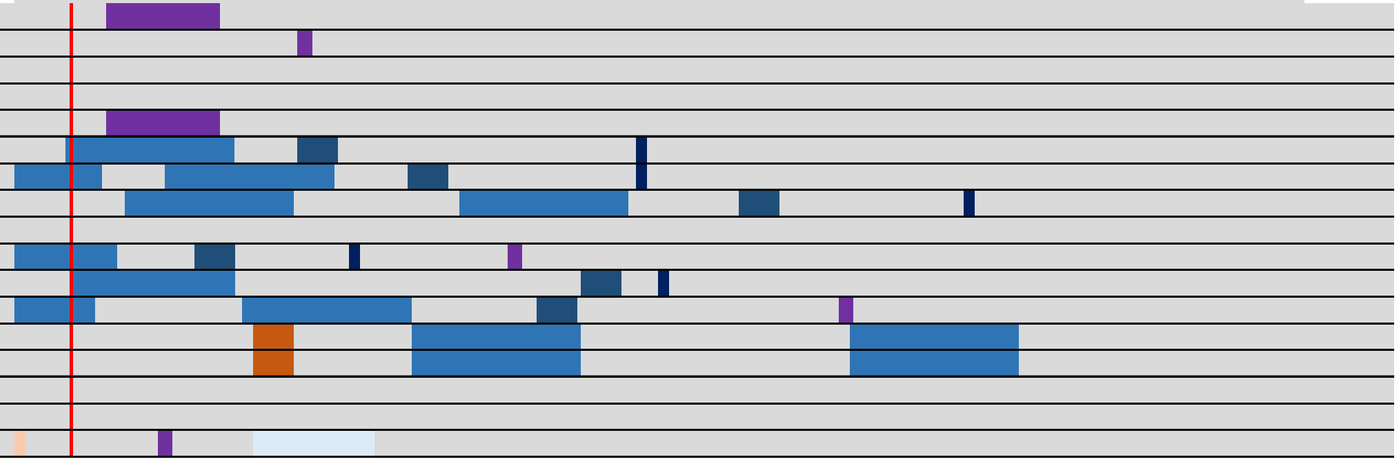
SUMMARY
Tutorial Video (11 min)
Click here to report technical issues

Updated: 8/31/2016

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

HOME

Project (Filter)	Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
2007-06.2 - Phase 2 System Protection Coordi	PRC-001-1.1.(Ret), PER-006-1	69	Current
2010-14.2.2 - Phase 2 of Balancing Authority F	BAL-004	(7)	Current
2013-03 - Geomagnetic Disturbance Mitigatio	TPL-007-1		Current
2015-04 - Alignment of Terms	Report on process (Phase II Im		Current
2015-07 - Internal Communications Capabilitie	COM-001-3	(74)	Current
2015-08 - Emergency Operations	EOP-005, EOP-006, and EOP-0	(148)	Current
2015-08 - Emergency Operations	EOP-004	(101)	Current
2015-09 - Establish and Communicate System	FAC-010-3, FAC-011-3, and FA	(58)	Current
2015-10 - Single Points of Failure TPL-001	TPL-001		Current
2015-INT-01 - Interpretation of CIP-002-5.1 fo	Interpretation CIP-002-5.1		Current
2016-01 - Modifications to TOP and IRO Stand	TOP/IRO Standards		Current
2016-02 - Modifications to CIP Standards	LERC Definition		Current
2016-02 - Modifications to CIP Standards	Directives, Control Center Con		Current
2016-02 - Modifications to CIP Standards	V5TAG, CA and BCA Definition		Current
2016-EPR-01 - Enhanced Periodic Review of Pe	PER Stds.		Current
2016-EPR-02 - Enhanced Periodic Review of V	VAR-001-4.1 & VAR-002-4		Current
2016-03 - Cyber Security Supply Chain Manage	New and revised Standard(s)		Current



Project	Project Name	Status	Comments	Deliverable	Deadline	Priority in 2016-2018 RSDP, if applicable (see	P81 Req (2013)	Number of Directives	No. of Guidances (see Note 2)	Directionally consistent with IERP findings (See Note 5)	Developer	PMOS Liaison
2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Pending Board Adoption	Filing anticipated in late November or December	BAL-004	N/A	N/A	N/A	N/A	4	N/A	Darrel Richardson	Ken Goldsmith
2013-03	Geomagnetic Disturbance Mitigation	Pending Regulatory Approval	NOPR issued May 14, 2015. FERC established additional comment period in October 2015 for responses to material filed following NOPR comments. FERC Staff technical conference held Mar 2016. Pending Final Rule. NERC filed correction to project white papers on June 28, 2016. Pending final rule.	TPL-007-1	N/A	N/A	N/A	N/A	N/A	N/A	Mark Olson	Jennifer Sterling
2015-04	Alignment of Terms	Other	SDT is developing recommendations to present to SC. The Phase II work was completed in February 2016 and the proposed recommendations were submitted for consideration at the March 2016 meeting. The item was pulled from the SC agenda based on a request from the SC chair, Brian Murphy. The SDT reviewed the revisions proposed by the SC chair, and determined to move forward with submitting the recommendations as developed by the SDT. The Phase II recommendation document will be resubmitted for inclusion on the September 2016 SC	Report on process (Phase II Improvement Report)	N/A	N/A	N/A	N/A	N/A	N/A	Lacey Ourso	Andrew Gallo
2015-07	Internal Communications Capabilities	Pending Regulatory Filing	Filing anticipated in late August.	COM-001-3	N/A	HIGH	N/A	1	N/A	N/A	Darrel Richardson	Brenda Hampton
2015-08	Emergency Operations	Posted	Posted for a 45-day initial comment period and ballot.	EOP-005, EOP-006, and EOP-008	N/A	Medium	N/A	1	N/A	N/A	Laura Anderson	Ken Goldsmith
2015-08	Emergency Operations	Working to Initial Posting	Planning to post for an initial comment and ballot in late July 2016.	EOP-004	N/A	Medium	N/A	1	N/A	N/A	Laura Anderson	Ken Goldsmith
2015-09	Establish and Communicate System Operating Limits	Working to Initial Ballot	Proposed revisions to FAC-11-3 and FAC-014-2 were posted for a 30-day informal comment period, from July 14 through August 12. The SDT is scheduled to meet August 23-25 to review the comments and continue drafting revisions to the FAC standards. If the team is able to finalize their proposed revisions at the upcoming meeting, then the revisions will be submitted for authorization to post at the September 14 Standards Committee meeting. However, it will all depend on the nature and volume of comments received through the comment period. More than likely, the SDT will need more time to finalize the draft standards, so I would anticipate us going to the SC for authorization to post at the October or November	FAC-010-3, FAC-011-3, and FAC-014-2	N/A	Medium	N/A	N/A	N/A	N/A	Lacey Ourso	Andrew Gallo
2015-10	Single Points of Failure TPL-001	Nominations	Revisions made to the SAR at the March 21-23, 2016 SAR ST meeting. Revisions are adding two outstanding FERC Directives from Order 786 (p. 40 and 89). Additionally, the retired MOD standards stated in TPL-001-4 Requirement R1 will be updated with the current MOD standard. The SAR is currently out for a 30-day informal comment period (May 26-June 24). A projected schedule has not been set by the SDT	TPL-001	N/A	High	N/A	N/A	N/A	N/A	Jordan Mallory / Al McMeekin	Mark Pratt
2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Working to Initial Ballot	SC approved RFI and for a project team to be formed in April 2016. The CIP SDT under Project 2016-02 is addressing this RFI.	Interpretation CIP-002-5.1	N/A	N/A	N/A	N/A	N/A	N/A	Al McMeekin	Brian Murphy
2016-01	Modifications to TOP and IRO Standards	Posted	NOPR issued June 18, 2015 (under previous project 2014-03). Final Rule issued November 19, 2015 with three directives with an associated 18 month regulatory filing deadline. The SC authorized posting at the June 2016 SC meeting. SDT is considering stakeholder comments and revising proposed	TOP/IRO Standards	FERC deadline of July 27, 2017	N/A	N/A	N/A	N/A	N/A	Mark Olson	Rod Kinard
2016-02	Modifications to CIP Standards	Posted	Currently in initial comment and ballot.	LERC Definition	Directive: March 31, 2017 (LERC only) (March 31 in SAR)	High	N/A	1	N/A	N/A	Al McMeekin	Brian Murphy
2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	Standing Review Team	Project is on hold until the SC Standing Review Team completes their grading and 30 day posting. Project expected to kick-off in September 2016.	PER Stds.	N/A	N/A	N/A	N/A	N/A	N/A	Darrel Richardson	Mike Brytowski
2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive Standards	Standing Review Team	Project is on hold until the SC Standing Review Team completes their grading and 30 day posting. Project expected to kick-off in September 2016.	VAR-001-4.1 & VAR-002-4	N/A	N/A	N/A	N/A	N/A	N/A	Scott Barfield-McGinnis	Amy Casuscelli

Project	**2007-06.2**
Project Name	Phase 2 System Protection Coordination
Status	Pending Regulatory Approval
Comments	The standard passed overwhelmingly along with the definitions. BOT adopted August 11, 2016 and filed with FERC on September 2, 2016.
Deliverable	PRC-001-1.1.(Ret), PER-006-1 (New), and revision to definitions of Operational Planning Analysis and Real-time Assessment.
Deadline	NERC-imposed deadline of 12/31/2015
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	1 - Move PRC-001, R1 to Training
Number of Directives	6
No. of Guidances (see Note 2)	1
Directionally consistent with IERP findings (See Note 5)	Yes - PRC-001-1.1(ii), R1 was noted as duplicative of TOP-006-2 R3, but TOP-006 was retired without addressing R1 under TOP/IRO in 2015.
Developer	Scott Barfield-McGinnis
PMOS Liaison	Brenda Hampton
Affected Standards	PRC-001-1.1.(ret.), PER-006-1 (new)

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT	1/6/2015	1/20/2015	1/30/2015	2/13/2015	24		
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/11/2007	7/10/2007	6/11/2007	7/10/2007			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/29/2015	9/11/2015	5/11/2015	6/25/2015	(79)	Regulatory Meeting	62.55%
CAB - Com/Add Ballot 2	10/6/2015	11/19/2015	7/27/2015	9/10/2015	(71)	Baseline Reset	57.29%
CAB - Com/Add Ballot 3	3/10/2016	4/30/2016	2/14/2016	3/30/2016	(25)	Change in Approach	80.57%
CAB - Com/Add Ballot 4			6/1/2016	7/16/2016		Not needed	
CAB - Com/Add Ballot 5							
FB - Final Ballot	5/17/2016	5/26/2016	7/25/2016	8/4/2016	69		82.52%
PTB - Present to BOT	8/10/2016	8/12/2016	8/10/2016	8/12/2016			
Filing - Filing with Regulators	***9/10/2016***	***10/10/2016***	9/10/2016	10/10/2016			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain the delay	5/1/2015	Did not pass Septmber 2015 ballot and will plan to conduct another SDT meeting and post for additional ballot. Goal to post end of January 2016; however, the SDT's plan to present a PER-005-2 revision met industry opposition during informal outreach. The SDT held a technical conference to resolve - resulting in PER-006-1 and definition changes to OPA and RTA. The first formal comment period for PER-006-1 runs March 10 to April 25 with an initial ballot.
Explain early finish	6/1/2016	PER-006-1 did not require an additional planned ballot, passed on initial.

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

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	3/17/2015	4/15/2015	1/15/2015	2/14/2015	(61)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	8/12/2015	8/25/2015	4/1/2015	5/1/2015	(133)		
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/24/2015	11/12/2015	10/1/2015	11/15/2015	7		
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	12/8/2015	12/17/2015	12/1/2015	12/11/2015	(7)		
PTB - Present to BOT	2/10/2016	2/12/2016	5/1/2016	5/3/2016	81		
Filing - Filing with Regulators	11/1/2016	11/4/2016	6/1/2016	6/11/2016	(153)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes

Project	**2013-03**
Project Name	Geomagnetic Disturbance Mitigation
Status	Pending Regulatory Approval
Comments	NOPR issued May 14, 2015. FERC established additional comment period in October 2015 for responses to material filed following NOPR comments. FERC Staff technical conference held Mar 2016. Pending Final Rule. NERC filed correction to project white papers on June 28, 2016. Pending final rule.
Deliverable	TPL-007-1
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mark Olson
PMOS Liaison	Jennifer Sterling
Affected Standards	TPL-007-1

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

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

Project	**2015-04**
Project Name	Alignment of Terms
Status	Other
Comments	SDT is developing recommendations to present to SC. The Phase II work was completed in February 2016 and the proposed recommendations were submitted for consideration at the March 2016 meeting. The item was pulled from the SC agenda based on a request from the SC chair, Brian Murphy. The SDT reviewed the revisions proposed by the SC chair, and determined to move forward with submitting the recommendations as developed by the SDT. The Phase II recommendation document will be resubmitted for inclusion on the September 2016 SC agenda.
Deliverable	Report on process (Phase II Improvement Report)
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Lacey Ourso
PMOS Liaison	Andrew Gallo
Affected Standards	Glossary/ROP

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes

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

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT	6/11/2015	6/24/2015	6/1/2015	6/15/2015	(10)		
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/11/2015	7/11/2015	6/1/2015	7/1/2015	(10)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/25/2015	11/16/2015	7/15/2015	8/29/2015	(72)		
CAB - Com/Add Ballot 2	3/23/2016	5/9/2016	10/1/2015	11/15/2015	(174)		
CAB - Com/Add Ballot 3			1/1/2016	2/15/2016		Not needed	
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	6/14/2016	6/24/2016	4/1/2016	4/11/2016	(74)		83.25%
PTB - Present to BOT	8/10/2016	8/12/2016	5/6/2016	5/8/2016	(96)		
Filing - Filing with Regulators	8/10/2016	8/12/2016	8/10/2016	8/12/2016			
PT - Post Approval Training	***9/10/2016***	***10/10/2016***	9/10/2016	10/10/2016			

PTS Change Control

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

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

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review			1/11/2016	1/21/2016			
SP1 - SAR/PR/WP Posting 1	7/21/2015	8/19/2015	7/15/2015	8/14/2015	(6)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	6/29/2016	8/12/2016	1/25/2016	3/10/2016	(156)		
CAB - Com/Add Ballot 2	***8/30/2016***	***10/14/2016***	***4/4/2016***	***5/19/2016***	(148)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	11/1/2016	11/11/2016	6/6/2016	6/16/2016	(148)		
PTB - Present to BOT	2/1/2017	2/3/2017	8/8/2016	8/10/2016	(177)		
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

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

Project	**2015-08**
Project Name	Emergency Operations
Status	Working to Initial Posting
Comments	Planning to post for an initial comment and ballot in late July 2016.
Deliverable	EOP-004
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	Medium
P81 Req (2013)	N/A
Number of Directives	1
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Laura Anderson
PMOS Liaison	Ken Goldsmith
Affected Standards	EOP-004

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review			1/11/2016	1/21/2016			
SP1 - SAR/PR/WP Posting 1	7/21/2015	8/19/2015	7/15/2015	8/14/2015	(6)		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/25/2016	9/8/2016	4/18/2016	6/2/2016	(98)		
CAB - Com/Add Ballot 2	9/26/2016	11/10/2016	6/27/2016	8/11/2016	(91)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	12/1/2016	12/11/2016	8/22/2016	9/1/2016	(101)		
PTB - Present to BOT	2/1/2017	2/3/2017	10/31/2016	11/2/2016	(93)		
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

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

Project	**2015-09**	**Home**
Project Name	Establish and Communicate System Operating Limits	
Status	Working to Initial Ballot	
Comments	Proposed revisions to FAC-11-3 and FAC-014-2 were posted for a 30-day informal comment period, from July 14 through August 12. The SDT is scheduled to meet August 23-25 to review the comments and continue drafting revisions to the FAC standards. If the team is able to finalize their proposed revisions at the upcoming meeting, then the revisions will be submitted for authorization to post at the September 14 Standards Committee meeting. However, it will all depend on the nature and volume of comments received through the comment period. More than likely, the SDT will need more time to finalize the draft standards, so I would anticipate us going to the SC for authorization to post at the October or November meeting.	
Deliverable	FAC-010-3, FAC-011-3, and FAC-014-2	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Lacey Ourso	
PMOS Liaison	Andrew Gallo	
Affected Standards	FAC-010-3, FAC-011-3, and FAC-014-2	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review			4/4/2016	4/14/2016		Not needed	
SP1 - SAR/PR/WP Posting 1	8/20/2015	9/21/2015	8/20/2015	9/21/2015			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	7/8/2016	8/7/2016	7/8/2016	8/7/2016			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***9/15/2016***	***10/30/2016***	4/18/2016	6/2/2016	(150)		
CAB - Com/Add Ballot 2	12/15/2016	1/29/2017	7/18/2016	9/1/2016	(150)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	3/1/2017	3/11/2017	1/2/2017	1/12/2017	(58)		
PTB - Present to BOT	5/1/2017	5/3/2017	2/1/2017	2/3/2017	(89)		
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain delay	5/1/2016	The apparent delay in the project is due to missing an earlier update to the PMOS Annual Project Calendar. Baseline Schedule has not been adjusted.
Up coming action	9/14/2016	Schedule baseline correction to address problem noted above.

Project	**2015-10**	**Home**
Project Name	Single Points of Failure TPL-001	
Status	Nominations	
Comments	Revisions made to the SAR at the March 21-23, 2016 SAR ST meeting. Revisions are adding two outstanding FERC Directives from Order 786 (p. 40 and 89). Additionally, the retired MOD standards stated in TPL-001-4 Requirement R1 will be updated with the current MOD standard. The SAR is currently out for a 30-day informal comment period (May 26-June 24). A projected schedule has not been set by the SDT.	
Deliverable	TPL-001	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Jordan Mallory / Al McMeekin	
PMOS Liaison	Mark Pratt	
Affected Standards	TPL-001	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR	11/12/2015	12/1/2015	1/18/2016	2/1/2016	67		
Nominations - DT	7/22/2016	8/5/2016	7/25/2016	8/8/2016	3		
QR - Quality Review			5/30/2016	6/9/2016			
SP1 - SAR/PR/WP Posting 1	11/12/2015	12/17/2015	11/12/2015	12/17/2015			
SP2 - SAR/PR/WP Posting 2	5/26/2016	6/24/2016	6/15/2016	7/15/2016	20	Expanded Scope	
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Expansion of Scope	6/14/2016	FERC directives added additional scoping in addition to industry comments following the second SAR posting. The MOD references are being updated due to some retiring in July

Project	**2015-INT-01**
Project Name	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)
Status	Working to Initial Ballot
Comments	SC approved RFI and for a project team to be formed in April 2016. The CIP SDT under Project 2016-02 is addressing this RFI.
Deliverable	Interpretation CIP-002-5.1
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Al McMeekin
PMOS Liaison	Brian Murphy
Affected Standards	CIP-002-5.1

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT			4/15/2016	4/29/2016			
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/27/2016	9/12/2016	7/25/2016	9/8/2016	(2)		
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/4/2016	10/14/2016	10/4/2016	10/14/2016			
PTB - Present to BOT	11/15/2016	11/17/2016	11/15/2016	11/17/2016			
Filing - Filing with Regulators	12/28/2016	12/31/2016	12/28/2016	12/31/2016			
PT - Post Approval Training							

PTS Change Control

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

Project	**2016-01**
Project Name	Modifications to TOP and IRO Standards
Status	Posted
Comments	NOPR issued June 18, 2015 (under previous project 2014-03). Final Rule issued November 19, 2015 with three directives with an associated 18 month regulatory filing deadline. The SC authorized posting at the June 2016 SC meeting. SDT is considering stakeholder comments and revising proposed standards.
Deliverable	TOP/IRO Standards
Deadline	FERC deadline of July 27, 2017
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mark Olson
PMOS Liaison	Rod Kinard
Affected Standards	TOP/IRO Standards

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT	1/22/2016	2/4/2016	4/18/2016	5/2/2016	87		
QR - Quality Review	5/10/2016	5/23/2016	6/27/2016	7/7/2016	48		
SP1 - SAR/PR/WP Posting 1	1/22/2016	2/22/2016	3/7/2016	4/6/2016	45		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	6/20/2016	8/3/2016	7/11/2016	8/25/2016	21		IRO-002-5 (67.25%) TOP-001-4 (64.59%)
CAB - Com/Add Ballot 2	***8/31/2016***	***10/14/2016***	10/24/2016	12/8/2016	54		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/17/2017	1/27/2017	1/17/2017	1/27/2017			
PTB - Present to BOT	2/7/2017	2/9/2017	2/7/2017	2/9/2017			
Filing - Filing with Regulators	7/24/2016	7/27/2016	7/24/2016	7/27/2016			
PT - Post Approval Training							

PTS Change Control

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

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

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT	3/10/2016	3/24/2016	3/10/2016	3/24/2016			
QR - Quality Review	6/30/2016	7/6/2016	6/30/2016	7/7/2016			
SP1 - SAR/PR/WP Posting 1	3/23/2016	4/21/2016	3/23/2016	4/21/2016			
SP2 - SAR/PR/WP Posting 2	6/1/2016	6/30/2016	6/1/2016	7/1/2016		Expanded Scope	
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/21/2016	9/6/2016	7/25/2016	9/8/2016	4		
CAB - Com/Add Ballot 2	10/17/2016	12/1/2016	10/17/2016	12/1/2016			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/5/2017	1/15/2017	1/5/2017	1/15/2017			
PTB - Present to BOT							
Filing - Filing with Regulators	3/28/2017	3/31/2017	3/28/2017	3/31/2017			
PT - Post Approval Training							

PTS Change Control

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

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

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	12/2/2016	1/16/2017	12/2/2016	1/16/2017			
CAB - Com/Add Ballot 2	3/31/2017	5/15/2017	3/31/2017	5/15/2017			
CAB - Com/Add Ballot 3	8/15/2017	9/29/2017	8/15/2017	9/29/2017			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/17/2017	10/27/2017	10/17/2017	10/27/2017			
PTB - Present to BOT	11/7/2017	11/9/2017	11/7/2017	11/9/2017			
Filing - Filing with Regulators	12/28/2016	12/31/2016	12/28/2016	12/31/2016			
PT - Post Approval Training							

PTS Change Control

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

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	SAR	
Comments	Draft rationale/purpose statements, consider requirement structures, Draft requirement language, Take a close look at Measures; To QR - Oct 20; SC Mtg - Nov 17 (Nov 3 SC agenda); (will require scheduling an off-cycle meeting)	
Deliverable	V5TAG, CA and BCA Definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), TO Control Centers, Virtualization	
Deadline	N/A	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	High	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS	Brian Murphy	
Affected Standards	CIP Standards	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	12/2/2016	1/16/2017	12/2/2016	1/16/2017			
CAB - Com/Add Ballot 2	3/31/2017	5/15/2017	3/31/2017	5/15/2017			
CAB - Com/Add Ballot 3	8/15/2017	9/29/2017	8/15/2017	9/29/2017			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/17/2017	10/27/2017	10/17/2017	10/27/2017			
PTB - Present to BOT	11/7/2017	11/9/2017	11/7/2017	11/9/2017			
Filing - Filing with Regulators	12/28/2016	12/31/2016	12/28/2016	12/31/2016			
PT - Post Approval Training							

PTS Change Control

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

Project	**2016-EPR-01**
Project Name	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards
Status	Standing Review Team
Comments	Project is on hold until the SC Standing Review Team completes their grading and 30 day posting. Project expected to kick-off in September 2016.
Deliverable	PER Stds.
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Darrel Richardson
PMOS Liaison	Mike Brytowski
Affected Standards	PER Stds.

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes

Project	**2016-EPR-02**
Project Name	Enhanced Periodic Review of Voltage and Reactive Standards
Status	Standing Review Team
Comments	Project is on hold until the SC Standing Review Team completes their grading and 30 day posting. Project expected to kick-off in September 2016.
Deliverable	VAR-001-4.1 & VAR-002-4
Deadline	N/A
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Scott Barfield-McGinnis
PMOS Liaison	Amy Casuscelli
Affected Standards	VAR-001-4.1 & VAR-002-4

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR							
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes

Project	**2016-03**	**Home**
Project Name	Cyber Security Supply Chain Management	
Status	Nominations	
Comments	The project will address directives from Federal Energy Regulatory Commission (FERC) Order No. 829 to develop a new or modified standard to address "supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations." See Order No. 829, at P 1.	
Deliverable	New and revised Standard(s)	
Deadline	Tuesday, September 27, 2016	
Priority in 2016-2018 RSDP, if applicable (see Note 1)	N/A	
P81 Req (2013)	N/A	
Number of Directives	1	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mark Olson	
PMOS Liaison	Brenda Hampton	
Affected Standards	New and revised Standard(s)	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR					0		
Nominations - DT	7/29/2016	8/18/2016	7/29/2016	8/18/2016	0		
QR - Quality Review					0		
SP1 - SAR/PR/WP Posting 1	10/20/2016	11/21/2016	10/20/2016	11/21/2016	0		
SP2 - SAR/PR/WP Posting 2					0		
CP1 - Comment Period 1					0		
CP2 - Comment Period 2					0		
CIB - Com/Ballot 1 (Initial)					0		
CAB - Com/Add Ballot 2					0		
CAB - Com/Add Ballot 3					0		
CAB - Com/Add Ballot 4					0		
CAB - Com/Add Ballot 5					0		
FB - Final Ballot					0		
PTB - Present to BOT	8/9/2017	8/11/2017	8/9/2017	8/11/2017	0		
Filing - Filing with Regulators	9/24/2016	9/27/2016	9/24/2016	9/27/2016	0		
PT - Post Approval Training					0		

PTS Change Control

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

No.	Description
Note 1	The prioritizations here reflect those prioritizations assigned as part of the 2015-2017 Reliability Standards Development Plan (RSDP). In its approach to prioritizing Reliability Standards projects, the RSDP considered how Reliability Standard family priorities are applied to individual projects and outstanding work. Specific elements included: (1) RISC Category Rankings; (2) regulatory directives; (3) regulatory deadlines; (4) Reliability Standard requirement candidates for retirement; (5) the IERP content and quality assessments; and (6) additional considerations (fill-in-the-blank status and five-year assessment commitments). Some projects were not prioritized in the RSDP, as they were originally anticipated to be complete before the end of the first quarter of 2015, and those projects have an "N/A" designation in this column. Other projects have been added to the Project Tracking Spreadsheet that were not prioritized in the RSDP. These were added in response to regulatory directives that were issued following completion of the RSDP, and they will be prioritized according to the same process during the first quarter of 2015 according to the same process described in the RSDP. Those projects are designated as "Pending Prioritization in 1Q 2015." As discussed in the 2015-2017 RSDP, the prioritization will occur in collaboration between NERC Staff and the Standards Committee.
Note 2	Refers to guidances from regulatory orders for standards activity to consider, but that do not carry the same effect as a directive.
Note 3	In the columns at right, in some cases, an "additional ballot" is not indicated for planning purposes, but if consensus is not supported on an initial ballot, or if substantive changes occur, one will be scheduled.
Note 4	In the columns at right, there are no "plan" milestones in some cases because the project was originally planned to be complete in 2014, and the project's "actual" milestones have extended into 2015).
Note 5	In the column labeled "directionally consistent with IERP findings," directionally consistent indicates whether the Standard Drafting Team, when the project is completed, considered the recommendations from the Independent Expert Review Project and the Paragraph 81 project. After the Standard Drafting Team has considered the recommendations, the materials posted with the standards will describe the Standard Drafting Team's consideration of the findings.
Note 6	
Note 7	
Note 8	
Note 9	
Note 10	

RSC Meeting #16-5, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Guy Zito will follow up with CCC on CIP-014 auditor practice guide and status of SAR.	Guy Zito	RSC Meeting	Ongoing
4.2	Si Truc Phan provide updates to the group on the status of GMD (Hydro Quebec Parameters)	Si Truc Phan	RSC Meeting	Ongoing
4.3	Ruida Shu will forward the phase one report on Cost Effectiveness Pilot to the RSC members when it is posted.	Ruida Shu	RSC Meeting	Completed
4.4	Ruida Shu will send HQ PRC-025-1 Generator Loadability issue to Scott Barfield.	Ruida Shu	RSC Meeting	Completed

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Weekly Standards & Compliance Bulletin

September 19–25, 2016

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-01 – Modifications to TOP and IRO Standards | IRO-002-5 and TOP-001-4	Additional Ballots and Non-binding Polls	10/05/16	10/14/16
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
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Posted for Comment (comment periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-01 – Modifications to TOP and IRO Standards | IRO-002-5 and TOP-001-4 **NEW** Draft RSAWs are posted through October 14, 2016. Submit comments to RSAWfeedback@nerc.net.	Comment Form	08/31/16	10/14/16
NEW Project 2016-04 – Modifications to PRC-025-1 | Standards Authorization Request	Comment Form	09/16/16	10/18/16

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Comment Period Open for Regional Reliability Standards MOD-026-2 and MOD-027-2 (WECC Variance): WECC has requested that NERC post the following two documents for industry review and comment in accordance with the NERC Rules of Procedure: • MOD-026-2, Verification of Models and Data for Generator Excitation Control System or Plant Volt/VA Control Functions – with WECC Regional Variance • MOD-027-2, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Function – with WECC Regional Variance The two documents were posted for 45-day comment November 13–December 28, 2015 and the comments received can be viewed here. In the first posting, a reference to "ten-years" was intended to be changed to "five-years," but it was overlooked. This posting corrects that oversight. Without these variances, an entity can use flawed generator modeling practices and still be in alignment with the requirements of MOD-026-1 and MOD-027-1, leaving questions of credibility of certain generator models. As a result, entities could plan their systems based on models whose veracity has never been determined. Use of these acceptable-yet-flawed practices creates inaccuracies in the WECC model databases. As a result, reliability is at risk without the variances.	Submit comments using the electronic form.	08/10/16	09/23/16

STANDARDS NEWS

NEW Standards Authorization Request Drafting Team Nomination Period Open

Nominations are being sought for SAR drafting team members for Project 2016-04 – Modifications to PRC-025-1 through September 28, 2016.

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

QUICK LINKS

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

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the SDT meetings. If appointed by the Standards Committee (SC), you are expected to attend most of the face-to-face meetings as well as participate in meetings held via conference calls.

The time commitment for this project is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the SAR drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the entire team for discussion and review. Lastly, an important component of the SAR drafting effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome. The SC is expected to appoint members to the team in October 2016. Nominees will be notified shortly after they have been appointed.

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW 2017 ERO Enterprise Compliance Monitoring and Enforcement Program Implementation Plan Posted

The 2017 ERO Enterprise Compliance Monitoring and Enforcement Program Annual Implementation Plan is now available on the NERC website. The Implementation Plan is the annual operating plan used by Compliance Enforcement Authorities (CEAs) to implement the CMEP. The CEAs, which include NERC and the eight Regional Entities (REs), carry out CMEP activities in accordance with the NERC Rules of Procedure and Appendix 4C.

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

This posting is the release of the ERO Enterprise CMEP IP, less the completed RE IPs. Per the NERC Rules of Procedure, REs will complete and submit a RE Implementation Plan for NERC review and approval on or about October 1, 2016. Once NERC approves the RE Implementation Plans, NERC will revise the ERO Enterprise CMEP IP, attaching the RE Implementation Plans as appendices, and repost.

NEW Resources Posted

NERC has posted the streaming webinar recording from the September 14, 2016 webinar that focused on the CIP Version 5 Reliability Standards that apply to registered entities with Low Impact BCS.

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

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

U.S. Enforcement Date	Standard(s)
October 1, 2016	CIP-004-6 – Cyber Security – Personnel & Training (Requirement 4.2)
	FAC-003-4 – Transmission Vegetation Management
	MOD-031-2 – Demand and Energy Data
January 1, 2017	IRO-010-2 - Reliability Coordinator Data Specification and Collection (Requirements R1 and R2);
	TOP-003-3 – Operational Reliability Data (all Requirements except R5)

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

	CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.1–2.2) CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirement 3.1)
	MOD-033-1 – Steady-State and Dynamic System Model Validation
January 1, 2018	PRC-026-1 – Relay Performance During Stable Power Swings (Requirement 1)
July 1, 2018	CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.3) CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirements 3.2, 3.2.1, 3.2.2)
	MOD-026-1 – Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions (Requirements R2, 2.1–2.1.6) MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions (Requirements R2, 2.1–2.1.5)
January 1, 2020	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements 2–4)

BOARD OF TRUSTEES AND FERC ACTION

NEW FERC Open Meeting Agenda

The agenda for the September 22, 2016 FERC Open Meeting has been posted. There are three items of interest to the ERO:

- Agenda Item E-4 -- RM15-11-000 -- Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events
- Agenda Item E-5 -- RM16-13-000 -- Reliability Standards for Balancing Authority Control and Facility Interconnection Requirements
- Agenda Item E-6 -- RD16-6-000 -- Reliability Standards for Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities and Real-time Reliability Monitoring and Analysis Capabilities

UPCOMING EVENTS

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

Workshops and Conferences

- Power Plant Model Verification and Testing Workshop – September 20–21, 2016, Atlanta | Details | Register | Agenda
- Monitoring and Situational Awareness Technical Conference – September 27–28, 2016, Folsom, CA | Register | Hotel and Travel Details | Previous Conference Presentations
- GridSecCon 2016 – October 18–21, 2016, Quebec City, Canada | Register | Register for hotel (hotel cutoff is September 23) | Details
- **NEW** Emerging Technology Roundtable – November 15–16, 2016, Atlanta | Register

Webinars

- **NEW** Reliability Issues Steering Committee Overview Webinar – Noon–1:00 p.m. Eastern, September 21, 2016 | Register

Standing Committee Meetings and Conference Calls

- Critical Infrastructure Protection Committee Meeting – September 20–21, 2016 | Albuquerque, NM |Register | Register for hotel| Agenda
- Member Representatives Committee Pre-Meeting Conference Call and Informational Webinar – 11:00 a.m.–12:30 p.m. Eastern, October 4, 2016 | Register
- Board of Trustees Committees, Member Representatives Committee, and Board of Trustees Meetings – November 1–2, 2016 | Atlanta | Register

Standard Drafting Team Meetings

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

- **NEW** Project 2016-EPR-01 – Enhanced Periodic Review of PER Standards Drafting Team Meeting – September 21–22, 2016, Charlotte, NC | Register

- **NEW** Project 2016-02 Modifications to CIP Standards Drafting Team Meeting – September 27–29, 2016, Winnipeg, MB Canada | Register
- **NEW** Project 2015-08 Emergency Operations Standard Drafting Team Meeting – October 3–7, 2016, Tampa, FL | Register
- **NEW** Project 2015-09 System Operating Limits Standard Drafting Team Meeting – October 3–5, 2016, Austin, TX | Register
- **NEW** Functional Model Advisory Group – October 25–27, 2016, Portland, OR | Register

ABOUT THE WEEKLY STANDARDS & COMPLIANCE BULLETIN

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

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

Scope of Work
for the
Regional Standards Committee (RSC)

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

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

Subsequent to receiving comments from NPCC stakeholders the RSC will be responsible for submitting those comments to FERC, NERC or other industry organizations as required.
The RSC is an open and balanced stakeholder committee inclusive of all stakeholders that provide for or are materially impacted by the reliability of the Bulk Electric System. The RSC meetings are open to all stakeholders who want to participate and meeting materials will be publicly posted on the NPCC Website.

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

The RSC will coordinate its work through the NPCC Standards Staff which will administer the NPCC Regional Standards Process and coordinate the review and submission of comments.

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

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

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

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

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

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

RSC Members should make every effort to attend scheduled meetings and when not available are required to identify and provide a qualified proxy participant. RSC business cannot be conducted in the absence of a quorum and it is essential that each RSC member make a commitment to be present.

A. NPCC Regional Standards Process Responsibilities

The RSC is responsible for managing the standards process for the development of ERO Standards, Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), definitions, variances, interpretations and clarifications in accordance with the NPCC Regional Standard Processes Manual. The RSC is responsible for ensuring the quality of all Standards-related materials.

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

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

B. NPCC Directory and Criteria Process Responsibilities

The RSC provides oversight for the development of NPCC Directories and the criteria within each document. The RSC will provide guidance to all NPCC Committees regarding the development of NPCC documents including Directories, Procedures and Guidelines. The RSC will be available to advise the NPCC BOD on any Directory and Criteria related matters.

C. NERC Reliability Standards Responsibilities

The RSC will:

- Provide a forum for NPCC review, coordination and submission of NPCC comments to existing or proposed NERC Reliability Standards when posted for NERC "Open Process Review."
- Provide a forum for NPCC to participate, solicit and provide Regional comments as Standard Authorization Requests (SARs) and their respective Reliability Standards are developed in accordance with the NERC Standard Development Processes Manual.
- Identify prospective reliability issues associated with new or revised NERC Reliability Standards and their potential impact on the NPCC Region, (i.e., Regional differences).
- Propose solutions or guide the development of the NERC Reliability Standards through effective and timely comments and soliciting NPCC participation on the SAR and Reliability Standard Drafting Teams.
- Develop and maintain a Web-Based Database for tracking and scheduling Standards development activities from a Regional perspective.
- Target a wide range of participants across the NPCC membership during the Standard commenting process. Develop databases and e-mail list servers to engage more members and to elicit different perspectives.
- Follow up on proposed and adopted changes to the NERC Standard Development Processes Manual and Rules of Procedure as they apply to Reliability Standards, and provide NPCC members with basic information (or pointers to the NERC Website) for a common understanding of the process.
- Coordinate the activities of NPCC members on Standard Drafting Teams, and encourage NPCC representation on all Standard Drafting Teams.
- Coordinate NPCC input to the ERO Compliance Guidance Policy in accordance with the Application Guidance Process.

D. FERC Activities Affecting Standards

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

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

Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 2016-2017

The following Regional Standards Committee (RSC) Work Plan activities for the calendar years of 2016 -2017 will be consistent with the NPCC 2016 and 2017 Business Plans and Budgets, Organizational and Strategic Goals both approved and in draft and will also continue to be supportive of the ongoing cost effective and results based standard development efforts. Also, the Work Plan is responsive to the NERC Reliability Standards Development Process and ERO strategic goals. In 2016-2017, expedited standards project schedules and enhanced periodic reviews of standards with the goal of achieving a "steady-state" of standard development will be the focus of the RSC.

Core Reliability Standards Committee Functions

- Monitor NERC's Reliability Issues Steering Committee (RISC) top reliability related issues and priorities for potential incorporation into NERC standards, for removal from standards or for incorporation into guidelines or other non-standards solutions. Provide and coordinate NPCC's input into those decisions.
- Coordinate and provide input to the development and prioritization of ERO reliability standards within the NERC Reliability Standards Development Plan.
- Review and support the ERO results-based standards initiative and ongoing standards development work towards the ERO goal of a 'steady-state' of standard development which is defined to be a core set of results-based standards achieving an adequate level of reliability and subject to little change.
- Promote the steady-state standards initiative throughout the Northeast.
- Continue to provide input to the development of a model for consideration of costs in NERC's Standards Development program. [Cost of Risk Reduction Analysis (CRRA) first draft and pilot.]
- Oversee, and participate in the regional standards development process and base any development, revision or retirement of NPCC Regional Reliability Standards on the reliability related needs of the Region or continent-wide ERO standards.
- Engage in the newly approved NERC Compliance Policy Guidance program.[1] Support the inputs through the NPCC Compliance Committee regarding the NERC CMEP Guidance Program.
- Coordinate NPCC Regional Standards development activity with the development of standards appearing in the NERC Reliability Standards Development Plan.
- Coordinate NPCC participation in the review and the revision of NERC Standards and addressing directives from FERC and any Provincial regulatory directives through the Enhanced Periodic Review process.
- Address emerging issues FERC might have with the NPCC Regional Standard Processes to promote consistency and support the ERO One Enterprise model.
- Conduct thorough reviews of all NERC Standards being developed or revised, and coordinate timely comments within the NPCC Region based on reliability needs, results based requirements,

[1]Application Guidance will require RSC support to ERO and Regional leadership to determine validity of proposed compliance approaches.

Paragraph 81, FERC directives and Enhanced Periodic Reviews.

- Develop and submit Standard Authorization Requests (SARs) for revisions when necessary to improve a Standard and address reliability related issues for approved or draft Standards.
- Develop ballot recommendations or "issues statements" for all NERC Standards under development.
- Review and develop ballot recommendations for all NERC Formal Interpretations to Standards.
- Identify candidates for NERC Standards Drafting Team members from the NPCC region to provide the NPCC perspective on Standards development.
- Provide guidance to NPCC regional Standard Drafting Teams in critical areas of results-based Standards, Violation Severity Levels, and Violation Risk Factor development as well as ensuring quality.
- Respond to FERC and Provincial filings and interrogatories on issues related to regional Standards.
- Serve as a liaison for the Northeast to the NERC Reliability Issues Steering Committee for all new and emerging reliability risks to the BES.
- Participate in the proceedings of various NERC groups to contribute to the continual improvement of NERC Standards and processes. These groups include but are not limited to:
    - NERC Standards Committee (SC)
    - NERC Standards Committee Process Subcommittee (SCPS)
    - NERC Project Management Oversight Subcommittee (PMOS)
    - NERC Functional Model Advisory Group (FMAG)
    - NERC SAR and Standards Drafting Teams (SDTs)
    - NERC Reliability Issues Steering Committee (RISC)
- Manage the development and revision of the regional reliability Directories including criteria clarifications as necessary and review all criteria to ensure consistency with NERC or regional Reliability Standards.
- Promote the NPCC criteria as being more specific or more stringent. Coordinate efforts with the NPCC Compliance Committee to facilitate further development of the NPCC Criteria Compliance Enforcement Program (CCEP) via Phase 2 of the Directory Project which was initiated to reformat the criteria section of each Directory into measurable NERC-style requirements.

NPCC Standard Activities

- Review the need for and development of regional Standards and requirements utilizing the NPCC Regional Standard Processes Manual if directed by the ERO as per Section 300 of the NERC Rules of Procedure, or as needed in response to the revision or development of the ERO standard(s).
- Address any outstanding issues with the regulatory authorities in the U.S. and all applicable Provincial authorities for regional Standards.
- Address any outstanding issues with the regulatory authorities in the U.S. and all applicable Provincial authorities for Regional Standard Authorization Requests (RSARs).
- Review and initiate action on RSARs upon their acceptance by NPCC's Regional Standards Process Manager.
- Coordinate development of initial drafts of new or revised regional Standards for drafting teams to begin work with as necessary.
- Develop proposed standards and clarifications utilizing regional technical committees as assigned by the NPCC Reliability Coordinating Committee or RSC.
- Work with the NPCC CC to develop the necessary compliance elements of the regional Standards, for example, Violation Severity Levels (VSLs).
- Implement the NPCC Cost Effective Analysis Procedure and apply it to Directories being revised or developed, and promote and participate in the NERC Cost of Risk Reduction Analysis (CRRA) application to the ERO draft continent-wide Standards.
- Review NERC SARs, Standards, and interpretations, and provide comments as well as participate in NERC processes.
- Ensure that the appropriate NPCC Task Forces review NERC Standards-related issuances, and provide input to support a consensus opinion.

- Solicit technically qualified candidates from NPCC to participate on each of the NERC Standard Drafting Teams and additional members to the regional drafting teams. Ensure sufficient regional representation exists on the drafting teams.
- Review FERC rulings and communicate the rulings to the NPCC Members and coordinate the issues for the Members.
- Participate in ballots for ERO Standards and provide recommended comments and ballot positions to the NPCC Members of the NERC Registered Ballot Body.
- Educate and notify stakeholders and regulators about issues related to Standards development.
- Provide a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task Force on Infrastructure Security and Technology (TFIST), and other NPCC Task Forces and Working Groups.
- Achieve NPCC reliability goals and objectives by initiating and efficiently completing Standards development activities.
- Leverage internet and web-based tool functionality to ensure interregional consistency, uniformity, and quality of regional Reliability Standards.
- Establish a long-term strategy for Standards improvement (i.e. feedback mechanisms from compliance and event analysis), and initiate implementation.
- Ensure the topics addressed by Reliability Standards reflect changing industry needs.
- Identify potential market issues for regional Standards through NPCC Reliability Coordinating Committee (RCC) reviews.
- Process Improvement
    - Coordinate implementation of the NERC Standards development processes and NPCC regional Standard processes and recommend revisions as necessary.
    - Participate in the revision and redrafting of the NERC Rules and Procedures related to standards development such as, but not limited to:
        - The NERC Functional Model Working Group (FMWG)
        - The NERC Regional Standards Group (RSG)
        - The NERC Standards Committee (SC)
        - The NERC Standards Committee Process Subcommittee (SCPS)
    - Establish goals/targets for NERC and NPCC Standards procedure improvement.
- Streamline and improve the regional standards process and continue to enhance program tools.
- Communications
    - Strengthen the relationship with the industry's technical committees to ensure adequate input to standards development.
    - Sponsor NPCC Workshops and participate in NERC Workshops to promote awareness and educate the industry in Standards-related activities.
    - Promote the reliability objectives of NERC Standards as appropriate to NPCC Members of the NERC Registered Ballot Body.
    - Educate and inform industry stakeholders through web-based tools such as "Webinars" and participation in NERC Reliability Standards Workshops, as necessary.
    - Update and inform governmental regulators and/or authorities on the Standards development work plan and processes through individual project discussions and NPCC meetings/conferences.
    - Develop Standards program communications that support NERC's overall communications platform.
    - Accomplish all directives of ERO and governmental and/or regulatory authorities with regard to regional Standards development and procedures.
    - Adhere to and surpass the ERO Reliability Standards Work Plan milestones, when practical, as they pertain to targets for the regional Standards.

NPCC Directory Criteria Activities

- Coordinate activities with the regulatory authorities in the U.S. and all applicable Provincial authorities for NPCC Directories.
- Coordinate Directory criteria requirements with regional Standards requirements to ensure no inconsistencies exist and identify potential areas for improvements.

- Develop filing for the Directories for the New York State Public Service Commission to fulfill obligations for the "Carve-out" outlined in Order 672 for mandatory adherence to more stringent regional criteria for New York State.
- Develop filings of Directories as required with the Provincial authorities as per the various Memorandums of Understanding.
- Communications
    - Develop and maintain NPCC Reliability Directories and NPCC guidance documents which will enable users, owners and operators of the international Bulk Power System in the Region to apply the more stringent NPCC regionally-specific criteria.
    - Identify future regional Standard opportunities by developing a set of regional reliability Directories incorporating the ERO Reliability Standards, regional Standards and regionally-specific more stringent criteria.

RSC 2016-2017 Deliverables

- Solicit and develop comments for all NERC Reliability Standards related postings, highlighting issues detrimental to the reliability of the Northeast, and develop consensus suggestions to address those issues.
- Participate and coordinate NPCC's input during the Enhanced Periodic Reviews of NERC Standards
- Coordinate and oversee the review of the NPCC regional Standards based on FERC approved NERC Standards and potential revisions and retirements to NPCC's Standards.
- Develop ballot recommendations and/or issues notifications for all posted NERC Standards ballots.
- Review NPCC Directory criteria to ensure consistency with NERC Reliability Standards.
- Participate in further development and application of the NERC Cost of Risk Reduction Analysis (CRRA).
- Participate in the revision of Section 11 of the ERO Standards Process Manual and Appendix 3A of the NERC ROP as necessary, to support compliance guidance policy activities.
- Participate in the revision of Section 7 of the ERO Standards Process Manual in response to FERC 5 year assessment concerns.
- Participate in two NPCC Standards and Compliance Workshops.
- Participate in two NERC Standards Workshops.
- Support the Compliance Guidance Policy's Application Guidance Development.

FERC Order 830 Transmission System Planned Performance for Geomagnetic Disturbance (GMD) Events

Guy V. Zito
NPCC RSC
October 5-6, 2016

FERC Order 830

- **Background**
- **TPL-007-1**
- **Spatial Averaging**
- **GMD Benchmark**
- **Directives**
- **Future Actions**

FERC Order 830

Background Phase 1 and 2 of Order 779 March 2013:

- Phase 1 Order No. 797, the Commission approved Reliability Standard EOP-010-1- implement operational procedures to mitigate the effects of GMDs
- Phase 2 Order 830, Approves TPL-007-1, effective 60 days after publishing in the Fed. Reg.- conduct initial and on-going vulnerability assessments, Contains 3 FERC Directives

FERC Order 830

- **TPL-007-1**
  - Applicable to PC, TP, TO, and GO as identified in the Section 4.2 (power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV)
  - 7 requirements
    - PC and TP identify responsibilities for modeling
    - Maintain the models for GMD
    - Voltage criteria for Benchmark GMD event
    - GMD Vulnerability Assessment every 60 calendar months
    - PC/TP provide GIC flow information to TO and GO
    - TO and GO perform transformer thermal impact assessment on 75 A/Phase applicable BES transformers
    - Develop a CAP if performance doesn't meet Table 1 in std.

FERC Order 830

- **Spatial Averaging:**
  - The averaging of geoelectric field amplitude readings within a given area
  - High latitude geoelectric field amplitudes for the period of January 1, 1993 – December 31, 2013 –Northern Europe
  - 10-s IMAGE (International Monitor for Auroral Geomagnetic Effects) magnetometer array observations
  - Quebec ground conductivity model used (low conductivity)
  - Four different station groups chosen spanning a square area of approximately 500 km in width
  - 1-in-100 year amplitude is approximately between 3-8 V/km
  - Reasonable approximation avoiding pessimistic local field amplitudes being applied. (avoids effects of temp. changing field directions and magnitudes)

FERC Order 830

- **Benchmark GMD (HILF considers probability)**
- **Characteristics of GMD impact on the BES**:
  - Geomagnetic Latitude
  - Earth Conductivity
  - Transformer Electrical Response-half cycle saturation results in Harmonics and VAR absorbtion
  - Transformer Thermal Effects (e.g. hot spot transformer heating) (5-20 min range T constants)
  - Geoelectric Field Waveshape (dB/dt)
  - Wide Area Geomagnetic Phenomena

FERC Order 830

- **Benchmark GMD Determination:**
  - A reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data (8V/km) (60 degrees latitude)
  - Scaling factors to account for local geomagnetic latitude
  - Scaling factors to account for local earth conductivity
  - A reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

FERC Order 830

- **FERC Directives:**
  - The calculation of the reference peak geoelectric field amplitude component of the benchmark GMD event definition
  - The collection and public availability of necessary GIC monitoring and magnetometer data
  - Deadlines for completing corrective action plans and the mitigation measures called for in corrective action plans

FERC Order 830

- **NERC to submit within six months from the effective date of this Final Rule a GMD Research Work Plan**
- **GMD Research Work Plan must include:**
  - Further analysis of the area over which spatial averaging should be calculated for stability studies, including performing sensitivity analyses on squares less than 500 km per side (e.g., 100 km, 200 km)
  - Further analyze earth conductivity models by, for example, using metered GIC and magnetometer readings to calculate earth conductivity and using 3-D readings
  - Determine whether new analyses and observations support modifying the use of single station readings around the earth to adjust the spatially averaged benchmark for latitude

FERC Order 830

- **GMD Research Work Plan must includes (continued):**
  - Research further aspects of the required thermal impact assessments
  - Conduct any GMD-related research areas generally that may impact the development of new or modified GMD Reliability Standards

FERC Order 830

- **Future Actions**
  - SAR
  - SDT – More Nominees?
  - Quebec Variance

- **Questions/Comments**

156 FERC ¶ 61,215
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM15-11-000; Order No. 830]

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events

(Issued September 22, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) approves Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, submitted Reliability Standard TPL-007-1 for Commission approval in response to a Commission directive in Order No. 779. Reliability Standard TPL-007-1 establishes requirements for certain registered entities to assess the vulnerability of their transmission systems to geomagnetic disturbance events (GMDs), which occur when the sun ejects charged particles that interact with and cause changes in the earth's magnetic fields. Applicable entities that do not meet certain performance requirements, based on the results of their vulnerability assessments, must develop a plan to achieve the performance requirements. In addition, the Commission directs NERC to develop modifications to Reliability Standard TPL-007-1: (1) to modify the benchmark GMD event definition set forth in

Attachment 1 of Reliability Standard TPL-007-1, as it pertains to the required GMD Vulnerability Assessments and transformer thermal impact assessments, so that the definition is not based solely on spatially-averaged data; (2) to require the collection of necessary geomagnetically induced current monitoring and magnetometer data and to make such data publicly available; and (3) to include a one-year deadline for the development of corrective action plans and two and four-year deadlines to complete mitigation actions involving non-hardware and hardware mitigation, respectively. The Commission also directs NERC to submit a work plan and, subsequently, one or more informational filings that address specific GMD-related research areas.

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

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

156 FERC ¶ 61,215
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events

Docket No. RM15-11-000

ORDER NO. 830

FINAL RULE

(Issued September 22, 2016)

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission approves Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events).[1] The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted Reliability Standard TPL-007-1 for Commission approval in response to a Commission directive in Order No. 779.[2] Reliability Standard TPL-007-1 establishes requirements for certain registered entities to assess the vulnerability of their transmission systems to geomagnetic disturbance events (GMDs), which occur when the sun ejects

[1] 16 U.S.C. 824o.

[2] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 78 FR 30,747 (May 23, 2013), 143 FERC ¶ 61,147, *reh'g denied*, 144 FERC ¶ 61,113 (2013).

charged particles that interact with and cause changes in the earth's magnetic fields. Reliability Standard TPL-007-1 requires applicable entities that do not meet certain performance requirements, based on the results of their vulnerability assessments, to develop a plan to achieve the requirements. Reliability Standard TPL-007-1 addresses the directives in Order No. 779 by requiring applicable Bulk-Power System owners and operators to conduct initial and on-going vulnerability assessments regarding the potential impact of a benchmark GMD event on the Bulk-Power System as a whole and on Bulk-Power System components.[3] In addition, Reliability Standard TPL-007-1 requires applicable entities to develop and implement corrective action plans to mitigate identified vulnerabilities.[4] Potential mitigation strategies identified in the proposed Reliability Standard include, but are not limited to, the installation, modification or removal of transmission and generation facilities and associated equipment.[5] Accordingly, Reliability Standard TPL-007-1 constitutes an important step in addressing the risks posed by GMD events to the Bulk-Power System.

2. In addition, pursuant to section 215(d)(5) of the FPA, the Commission directs NERC to develop modifications to Reliability Standard TPL-007-1: (1) to revise the

[3] *See* Reliability Standard TPL-007-1, Requirement R4; *see also* Order No. 779, 143 FERC ¶ 61,147 at PP 67, 71.

[4] *See* Reliability Standard TPL-007-1, Requirement R7; *see also* Order No. 779, 143 FERC ¶ 61,147 at P 79.

[5] *See* Reliability Standard TPL-007-1, Requirement R7.

benchmark GMD event definition set forth in Attachment 1 of Reliability Standard TPL-007-1, as it pertains to the required GMD Vulnerability Assessments and transformer thermal impact assessments, so that the definition is not based solely on spatially-averaged data; (2) to require the collection of necessary geomagnetically induced current (GIC) monitoring and magnetometer data and to make such data publicly available; and (3) to include a one-year deadline for the completion of corrective action plans and two- and four-year deadlines to complete mitigation actions involving non-hardware and hardware mitigation, respectively.[6] The Commission directs NERC to submit these revisions within 18 months of the effective date of this Final Rule. The Commission also directs NERC to submit a work plan (GMD research work plan) within six months of the effective date of this Final Rule and, subsequently, one or more informational filings that address specific GMD-related research areas.

I. Background

A. Section 215 and Mandatory Reliability Standards

3. Section 215 of the FPA requires the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced in the United States by the ERO, subject to Commission oversight, or by the Commission independently.[7]

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[6] 16 U.S.C. 824o(d)(5).

[7] *Id*. 824o(e).

B. GMD Primer

4. GMD events occur when the sun ejects charged particles that interact with and cause changes in the earth's magnetic fields.[8] Once a solar particle is ejected, it can take between 17 to 96 hours (depending on its energy level) to reach earth.[9] A geoelectric field is the electric potential (measured in volts per kilometer (V/km)) on the earth's surface and is directly related to the rate of change of the magnetic fields.[10] A geoelectric field has an amplitude and direction and acts as a voltage source that can cause GICs to flow on long conductors, such as transmission lines.[11] The magnitude of the geoelectric field amplitude is impacted by local factors such as geomagnetic latitude and local earth conductivity.[12] Geomagnetic latitude is the proximity to earth's magnetic north and south poles, as opposed to earth's geographic poles. Local earth conductivity is the ability of the earth's crust to conduct electricity at a certain location to depths of hundreds of kilometers down to the earth's mantle. Local earth conductivity impacts the magnitude

[8] North American Electric Reliability Corp., 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System at i-ii (February 2012), http://www.nerc.com/files/2012GMD.pdf (GMD Interim Report).

[9] *Id.* ii.

[10] *Id.*

[11] *Id.*

[12] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 4.

(i.e., severity) of the geoelectric fields that are formed during a GMD event by, all else being equal, a lower earth conductivity resulting in higher geoelectric fields.[13]

C. Order No. 779

5. In Order No. 779, the Commission directed NERC, pursuant to section 215(d)(5) of the FPA, to develop and submit for approval proposed Reliability Standards that address the impact of geomagnetic disturbances on the reliable operation of the Bulk-Power System. The Commission based its directive on the potentially severe, wide-spread impact on the reliable operation of the Bulk-Power System that can be caused by GMD events and the absence of existing Reliability Standards to address GMD events.[14]

6. Order No. 779 directed NERC to implement the directive in two stages. In the first stage, the Commission directed NERC to submit, within six months of the effective date of Order No. 779, one or more Reliability Standards (First Stage GMD 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.[15]

7. In the second stage, the Commission directed NERC to submit, within 18 months of the effective date of Order No. 779, one or more Reliability Standards (Second Stage

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[13] *Id.*

[14] Order No. 779, 143 FERC ¶ 61,147 at P 3.

[15] *Id.* P 2.

GMD Reliability Standards) that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole. The Commission directed that the Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity of GMD events a responsible entity must assess for potential impacts on the Bulk-Power System.[16] Order No. 779 explained that if the assessments identified potential impacts from benchmark GMD events, the Reliability Standards should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event. The Commission directed that the development of this plan could not be limited to considering operational procedures or enhanced training alone but should, subject to the potential impacts of the benchmark GMD events identified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, system configuration or location of specific equipment.[17] Order No. 779 observed that these strategies could, for example, include automatically blocking GICs from entering the Bulk-Power System, instituting specification requirements for

[16] *Id.*

[17] *Id.*

new equipment, inventory management, isolating certain equipment that is not cost effective to retrofit or a combination thereof.

D. Order No. 797

8. In Order No. 797, the Commission approved Reliability Standard EOP-010-1 (Geomagnetic Disturbance Operations).[18] NERC submitted Reliability Standard EOP-010-1 for Commission approval in compliance with the Commission's directive in Order No. 779 corresponding to the First Stage GMD Reliability Standards. In Order No. 797-A, the Commission denied the Foundation for Resilient Societies' (Resilient Societies) request for rehearing of Order No. 797. The Commission stated that the rehearing request "addressed a later stage of efforts on geomagnetic disturbances (i.e., NERC's future filing of Second Stage GMD Reliability Standards) and [that Resilient Societies] may seek to present those arguments at an appropriate time in response to that filing."[19] In particular, the Commission stated that GIC monitoring requirements should be addressed in the Second Stage GMD Reliability Standards.[20]

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[18] *Reliability Standard for Geomagnetic Disturbance Operations*, Order No. 797, 79 FR 35,911 (June 25, 2014), 147 FERC ¶ 61,209, *reh'g denied*, Order No. 797-A, 149 FERC ¶ 61,027 (2014).

[19] Order No. 797-A, 149 FERC ¶ 61,027 at P 2.

[20] *Id.* P 27 (stating that the Commission continues "to encourage NERC to address the collection, dissemination, and use of geomagnetic induced current data, by NERC, industry or others, in the Second Stage GMD Reliability Standards because such efforts could be useful in the development of GMD mitigation methods or to validate GMD models").

E. NERC Petition and Reliability Standard TPL-007-1

9. On January 21, 2015, NERC petitioned the Commission to approve Reliability Standard TPL-007-1 and its associated violation risk factors and violation severity levels, implementation plan, and effective dates.[21] NERC also submitted a proposed definition for the term "Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment" for inclusion in the NERC Glossary of Terms (NERC Glossary). NERC maintains that Reliability Standard TPL-007-1 is just, reasonable, not unduly discriminatory or preferential and in the public interest. NERC further contends that Reliability Standard TPL-007-1 satisfies the directive in Order No. 779 corresponding to the Second Stage GMD Reliability Standards.

10. NERC states that Reliability Standard TPL-007-1 applies to planning coordinators, transmission planners, transmission owners and generation owners who own or whose planning coordinator area or transmission planning area includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher.[22] NERC explains that the applicability criteria for qualifying transformers in Reliability Standard

[21] Reliability Standard TPL-007-1 is not attached to this final rule. Reliability Standard TPL-007-1 is available on the Commission's eLibrary document retrieval system in Docket No. RM15-11-000 and on the NERC website, www.nerc.com. NERC submitted an errata on February 2, 2015 containing a corrected version of Exhibit A (Proposed Reliability Standard TPL-007-1).

[22] A power transformer with a "high side wye-grounded winding" refers to a power transformer with windings on the high voltage side that are connected in a wye configuration and have a grounded neutral connection. NERC Petition at 13 n.32.

TPL-007-1 are the same as that for the First Stage GMD Reliability Standard in Reliability Standard EOP-010-1, which the Commission approved in Order No. 797.

11. Reliability Standard TPL-007-1 contains seven requirements. Requirement R1 requires planning coordinators and transmission planners to determine the individual and joint responsibilities in the planning coordinator's planning area for maintaining models and performing studies needed to complete the GMD Vulnerability Assessment required in Requirement R4.

12. Requirement R2 requires planning coordinators and transmission planners to maintain system models and GIC system models needed to complete the GMD Vulnerability Assessment required in Requirement R4.

13. Requirement R3 requires planning coordinators and transmission planners to have criteria for acceptable system steady state voltage limits for their systems during the benchmark GMD event described in Attachment 1 (Calculating Geoelectric Fields for the Benchmark GMD Event).

14. Requirement R4 requires planning coordinators and transmission planners to conduct a GMD Vulnerability Assessment every 60 months using the benchmark GMD event described in Attachment 1 to Reliability Standard TPL-007-1. The benchmark GMD event is based on a 1-in-100 year frequency of occurrence and is composed of four elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) a scaling factor to account for local geomagnetic latitude; (3) a scaling factor to account for local earth conductivity; and (4) a reference geomagnetic field time series or wave shape to facilitate time-domain

analysis of GMD impact on equipment.[23] The product of the first three elements is referred to as the regional geoelectric field peak amplitude.[24]

15. Requirement R5 requires planning coordinators and transmission planners to provide GIC flow information, to be used in the transformer thermal impact assessment required in Requirement R6, to each transmission owner and generator owner that owns an applicable transformer within the applicable planning area.

16. Requirement R6 requires transmission owners and generator owners to conduct thermal impact assessments on solely and jointly owned applicable transformers where the maximum effective GIC value provided in Requirement R5 is 75 amperes per phase (A/phase) or greater.

17. Requirement R7 requires planning coordinators and transmission planners to develop corrective action plans if the GMD Vulnerability Assessment concludes that the system does not meet the performance requirements in Table 1 (Steady State Planning Events).

[23] *See* Reliability Standard TPL-007-1, Att. 1; s*ee also* NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

[24] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

F. Notice of Proposed Rulemaking

18. On May 14, 2015, the Commission issued a notice of proposed rulemaking (NOPR) proposing to approve Reliability Standard TPL-007-1.[25] In addition, the Commission proposed to direct that NERC develop three modifications to Reliability Standard TPL-007-1. First, the Commission proposed to direct NERC to revise the benchmark GMD event definition in Reliability Standard TPL-007-1 so that the definition is not based solely on spatially-averaged data. Second, the Commission proposed to direct NERC to revise Reliability Standard TPL-007-1 to require the installation of GIC monitors and magnetometers where necessary. Third, the Commission proposed to direct NERC to revise Reliability Standard TPL-007-1 to require corrective action plans (Requirement R7) to be developed within one year and, with respect to the mitigation actions called for in the corrective action plans, non-hardware mitigation actions to be completed within two years of finishing development of the corrective action plan and hardware mitigation to be completed within four years. The NOPR also proposed to direct NERC to submit a work plan and, subsequently, one or more informational filings that address specific GMD-related research areas and sought comment on certain issues relating to the transformer thermal impact assessments

[25] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Notice of Proposed Rulemaking, 80 FR 29,990 (May 26, 2015), 151 FERC ¶ 61,134 (2015) (NOPR).

(Requirement R6) and the meaning of language in Table 1 of Reliability Standard TPL-007-1.

19. On August 20, 2015 and October 2, 2015, the Commission issued notices setting supplemental comment periods regarding specific documents. On March 1, 2016, Commission staff led a technical conference on Reliability Standard TPL-007-1 and issues raised in the NOPR.[26]

20. On April 28, 2016, NERC made a filing notifying the Commission that "NERC identified new information that may necessitate a minor revision to a figure in one of the supporting technical white papers. This revision would not require a change to any of the Requirements of the proposed Reliability Standard."[27] On June 28, 2016, NERC submitted the revised technical white papers referenced in the April 28, 2016 filing. On June 29, 2016, the Commission issued a notice setting a supplemental comment period regarding the revised technical white papers submitted by NERC on June 28, 2016.

21. In response to the NOPR and subsequent notices, 28 entities filed initial and supplemental comments. We address below the issues raised in the NOPR and comments. The Appendix to this Final Rule lists the entities that filed comments in response to the NOPR and in response to the supplemental comment period notices.

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[26] Written presentations at the March 1, 2016 Technical Conference and the Technical Conference transcript referenced in this Final Rule are accessible through the Commission's eLibrary document retrieval system in Docket No. RM15-11-000.

[27] NERC April 28, 2016 Filing at 1.

II. Discussion

22. Pursuant to section 215(d) of the FPA, the Commission approves Reliability Standard TPL-007-1 as just, reasonable, not unduly discriminatory or preferential and in the public interest. While we recognize that scientific and operational research regarding GMD is ongoing, we believe that the potential threat to the bulk electric system warrants Commission action at this time, including efforts to conduct critical GMD research and update Reliability Standard TPL-007-1 as appropriate.

23. First, we find that Reliability Standard TPL-007-1 addresses the directives in Order No. 779 corresponding to the development of the Second Stage GMD Reliability Standards. Reliability Standard TPL-007-1 does this by requiring applicable Bulk-Power System owners and operators to conduct, on a recurring five-year cycle,[28] initial and on-going vulnerability assessments regarding the potential impact of a benchmark GMD event on the Bulk-Power System as a whole and on Bulk-Power System components.[29] In addition, Reliability Standard TPL-007-1 requires applicable entities to develop and implement corrective action plans to mitigate vulnerabilities identified through those recurring vulnerability assessments.[30] Potential mitigation strategies identified in the

[28] A detailed explanation of the five-year GMD Vulnerability Assessment and mitigation cycle is provided in paragraph 103, *infra*.

[29] *See* Reliability Standard TPL-007-1, Requirement R4; *see also* Order No. 779, 143 FERC ¶ 61,147 at PP 67, 71.

[30] *See* Reliability Standard TPL-007-1, Requirement R7; *see also* Order No. 779, 143 FERC ¶ 61,147 at P 79.

proposed Reliability Standard include, but are not limited to, the installation, modification or removal of transmission and generation facilities and associated equipment.[31] Accordingly, Reliability Standard TPL-007-1 constitutes an important step in addressing the risks posed by GMD events to the Bulk-Power System.

24. The Commission also approves the inclusion of the term "Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment" in the NERC Glossary; Reliability Standard TPL-007-1's associated violation risk factors and violation severity levels; and NERC's proposed implementation plan and effective dates. The Commission also affirms, as raised for comment in the NOPR, that cost recovery for prudent costs associated with or incurred to comply with Reliability Standard TPL-007-1 and future revisions to the Reliability Standard will be available to registered entities.[32]

25. While we conclude that Reliability Standard TPL-007-1 satisfies the directives in Order No. 779, based on the record developed in this proceeding, the Commission determines that Reliability Standard TPL-007-1 should be modified to reflect the new information and analyses discussed below, as proposed in the NOPR. Accordingly, pursuant to section 215(d)(5) of the FPA, the Commission directs NERC to develop and submit modifications to Reliability Standard TPL-007-1 concerning: (1) the calculation of the reference peak geoelectric field amplitude component of the benchmark GMD

[31] *See* Reliability Standard TPL-007-1, Requirement R7.

[32] NOPR, 151 FERC ¶ 61,134 at P 49 n.60.

event definition; (2) the collection and public availability of necessary GIC monitoring and magnetometer data; and (3) deadlines for completing corrective action plans and the mitigation measures called for in corrective action plans. The Commission directs NERC to develop and submit these revisions for Commission approval within 18 months of the effective date of this Final Rule.

26. Furthermore, to improve the understanding of GMD events generally, the Commission directs NERC to submit within six months from the effective date of this Final Rule a GMD research work plan.[33] Specifically, we direct NERC to: (1) further analyze the area over which spatial averaging should be calculated for stability studies, including performing sensitivity analyses on squares less than 500 km per side (e.g., 100 km, 200 km); (2) further analyze earth conductivity models by, for example, using metered GIC and magnetometer readings to calculate earth conductivity and using 3-D readings; (3) determine whether new analyses and observations support modifying the use of single station readings around the earth to adjust the spatially averaged benchmark for latitude; (4) research, as discussed below, aspects of the required thermal impact assessments; and (5) in NERC's discretion, conduct any GMD-related research areas generally that may impact the development of new or modified GMD Reliability Standards. We expect that work completed through the GMD research work plan, as

[33] Following submission of the GMD research work plan, the Commission will notice the filing for public comment and issue an order addressing its proposed content and schedule.

well as other analyses facilitated by the increased collection and availability of GIC monitoring and magnetometer data directed herein, will lead to further modifications to Reliability Standard TPL-007-1 as our collective understanding of the threats posed by GMD events improves.

27. Below we discuss the following issues raised in the NOPR and NOPR comments: (1) the benchmark GMD event definition described in Reliability Standard TPL-007-1, Attachment 1 (Calculating Geoelectric Fields for the Benchmark GMD Event); (2) transformer thermal impact assessments in Requirement R6; (3) GMD research work plan; (4) collection and public availability of GIC monitoring and magnetometer data; (5) completion of corrective action plans in Requirement R7; (6) meaning of "minimized" in Table 1 (Steady State Planning Events) of Reliability Standard TPL-007-1; (7) NERC's proposed implementation plan and effective dates; and (8) other issues.

A. Benchmark GMD Event Definition

NERC Petition

28. NERC states that the purpose of the benchmark GMD event is to "provide a defined event for assessing system performance during a low probability, high magnitude GMD event."[34] NERC explains that the benchmark GMD event represents "the most severe GMD event expected in a 100-year period as determined by a statistical analysis

[34] NERC Petition at 15.

of recorded geomagnetic data."[35] The benchmark GMD event definition is used in the GMD Vulnerability Assessments and thermal impact assessment requirements of Reliability Standard TPL-007-1 (Requirements R4 and R6).

29. As noted above, NERC states that the benchmark GMD event definition has four elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) a scaling factor to account for local geomagnetic latitude; (3) a scaling factor to account for local earth conductivity; and (4) a reference geomagnetic field time series or wave shape to facilitate time-domain analysis of GMD impact on equipment.[36]

30. The standard drafting team determined that a 1-in-100 year GMD event would cause an 8 V/km reference peak geoelectric field amplitude at 60 degree geomagnetic latitude using Québec's earth conductivity.[37] The standard drafting team stated that:

> the reference geoelectric field amplitude was determined through statistical analysis using … field measurements from geomagnetic observatories in northern Europe and the reference (Quebec) earth model …. The Quebec earth model is generally resistive and the geological structure is relatively well understood. The statistical analysis resulted in a conservative peak geoelectric field amplitude of approximately 8 V/km …. The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years.[38]

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[35] *Id.*

[36] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5.

[37] *Id.*

[38] *Id.* (footnotes omitted).

31. The standard drafting team explained that it used field measurements taken from the IMAGE magnetometer chain, which covers Northern Europe, for the period 1993-2013 to calculate the reference peak geoelectric field amplitude used in the benchmark GMD event definition.[39] As described in NERC's petition, the standard drafting team "spatially averaged" four different station groups of IMAGE data, each spanning a square area of approximately 500 km (roughly 310 miles) in width.[40] The standard drafting team justified the use of spatial averaging by stating that Reliability Standard TPL-007-1 is designed to "address wide-area effects caused by a severe GMD event, such as increased var absorption and voltage depressions. Without characterizing GMD on regional scales, statistical estimates could be weighted by local effects and suggest unduly pessimistic conditions when considering cascading failure and voltage collapse."[41]

32. NERC states that the benchmark GMD event includes scaling factors to enable applicable entities to tailor the reference peak geoelectric field to their specific location

[39] *Id.* at 8. The International Monitor for Auroral Geomagnetic Effects (IMAGE) consists of 31 magnetometer stations in northern Europe maintained by 10 institutes from Estonia, Finland, Germany, Norway, Poland, Russia, and Sweden. *See* IMAGE website, http://space.fmi.fi/image/beta/?page=home#.

[40] As applied by the standard drafting team, spatial averaging refers to the averaging of geoelectric field amplitude readings within a given area. NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 9.

[41] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 9.

for conducting GMD Vulnerability Assessments. NERC explains that the scaling factors in the benchmark GMD event definition are applied to the reference peak geoelectric field amplitude to adjust the 8 V/km value for different geomagnetic latitudes and earth conductivities.[42]

33. The standard drafting team also identified a reference geomagnetic field time series from an Ottawa magnetic observatory during a 1989 GMD event that affected Québec.[43] The standard drafting team used this time series to estimate a geoelectric field, represented as a time series (i.e., 10-second values over a period of days), that is expected to occur at 60 degree geomagnetic latitude during a 1-in-100 year GMD event. NERC explains that this time series is used to facilitate time-domain analysis of GMD impacts on equipment.[44]

34. In the sub-sections below, we discuss two issues concerning the benchmark GMD event definition addressed in the NOPR: (1) reference peak geoelectric field amplitude; and (2) geomagnetic latitude scaling factor.

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[42] NERC Petition at 18-19.

[43] NERC Petition, Ex. D (White Paper on GMD Benchmark Event Description) at 5-6, 15-16 ("the reference geomagnetic field waveshape was selected after analyzing a number of recorded GMD events… the March 13-14, 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory, was selected as the reference geomagnetic field waveform because it provides generally conservative results when performing thermal analysis of power transformers").

[44] *Id.* at 5-6.

1. Reference Peak Geoelectric Field Amplitude

NOPR

35. The NOPR proposed to approve the benchmark GMD event definition. The NOPR stated that the "benchmark GMD event definition proposed by NERC complies with the directive in Order No. 779 … [c]onsistent with the guidance provided in Order No. 779, the benchmark GMD event definition proposed by NERC addresses the potential widespread impact of a severe GMD event, while taking into consideration the variables of geomagnetic latitude and local earth conductivity."[45]

36. In addition, the NOPR proposed to direct NERC to develop modifications to Reliability Standard TPL-007-1. Specifically, the NOPR proposed to direct NERC to modify the reference peak geoelectric field amplitude component of the benchmark GMD event definition so that it is not calculated based solely on spatially-averaged data. The NOPR explained that this could be achieved, for example, by requiring applicable entities to conduct GMD Vulnerability Assessments (and, as discussed below, thermal impact assessments) using two different benchmark GMD events: the first benchmark GMD event using the spatially-averaged reference peak geoelectric field value (8 V/km) and the second using the non-spatially averaged peak geoelectric field value cited in the GMD Interim Report (20 V/km). The NOPR stated that the revised Reliability Standard could then require applicable entities to take corrective actions, using engineering judgment,

[45] NOPR, 151 FERC ¶ 61,134 at P 32.

based on the results of both assessments. The NOPR explained that applicable entities would not always be required to mitigate to the level of risk identified by the non-spatially averaged analysis; instead, the selection of mitigation would reflect the range of risks bounded by the two analyses, and be based on engineering judgment within this range, considering all relevant information. The NOPR stated that, alternatively, NERC could propose an equally efficient and effective modification that does not rely exclusively on the spatially-averaged reference peak geoelectric field value.

Comments

37. NERC does not support revising the benchmark GMD event definition. NERC maintains that the spatially-averaged reference peak geoelectric field amplitude value in Reliability Standard TPL-007-1 is "technically-justified, scientifically sound, and has been published in a peer-reviewed research journal covering geomagnetism and other topics."[46] NERC contends that the standard drafting team determined that using the non-spatially averaged 20 V/km figure in the GMD Interim Report would "consistently overestimate the geoelectric field of a 1-in-100 year GMD event."[47] NERC states that, by contrast, spatial averaging "properly associates the relevant spatial scales for the analyzed and applied geoelectric fields and would not distort the complexity of the potential

[46] NERC Comments at 6.

[47] *Id.* at 7.

impacts of a GMD event."[48] NERC claims that the 500 km-wide square areas used to determine the areas of spatial averaging are "based on consideration of transmission systems and geomagnetic observation patterns … [and are] an appropriate scale for a system-wide impact in a transmission system."[49] To support this position, NERC cites a June 2015 peer-reviewed publication authored in part by some members of the standard drafting team.[50]

38. Industry commenters, largely represented by the Trade Associations' comments, do not support revising the benchmark GMD event definition.[51] The Trade Associations' reasons largely mirror NERC's. While recognizing that the spatially-averaged reference peak geoelectric field amplitude is lower than the non-spatially averaged figure, the Trade Associations contend that the non-spatially averaged value is inappropriate because: (1) the peak geoelectric field only affects relatively small areas and quickly

[48] *Id.* at 8.

[49] *Id.*

[50] *See* Pulkkinen, A., Bernabeu, E., Eichner, J., Viljanen, A., Ngwira, C., "Regional-Scale High-Latitude Extreme Geoelectric Fields Pertaining to Geomagnetically Induced Currents," Earth, Planets and Space (June 19, 2015) (2015 Pulkkinen Paper).

[51] Trade Associations Comments at 13-18. AEP, APS, ATC, BPA, CEA, Hydro One, ITC, Joint ISOs/RTOs and Exelon indicated that they do not support the NOPR proposal in separate comments and/or by joining the Trade Associations' comments. *See* AEP Comments at 3; APS Comments at 2; ATC Comments at 3; BPA Comments at 3-4; CEA Comments at 8-13; Hydro One Comments 1-2; ITC Comments at 3-5; Joint ISOs/RTOs Comments at 4-5; Exelon Comments at 2.

declines with distance from the peak; (2) Reliability Standard TPL-007-1 is intended to address the wide-scale effects of a GMD event; and (3) the benchmark GMD event definition is designed to provide a realistic estimate of wide-area effects caused by a severe GMD event. The Trade Associations contend that a non-spatially averaged reference peak geoelectric field amplitude "would be weighted by local effects and suggest unrealistic conditions for system analysis … [which] could lead to unnecessary costs for customers, while yielding very little tangible benefit to reliability."[52] Like NERC, the Trade Associations cite to the 2015 Pulkkinen Paper to support the use of 500 km-wide squares in performing the spatial averaging analysis. The Trade Associations note, however, that the selection of 500 km is "only the beginning … [of the] exploration of spatial geoelectric field structures pertaining to extreme GIC."[53]

39. The Trade Associations, while not supportive of the NOPR proposal, recommend that if the Commission remains concerned about relying on NERC's proposed spatially-averaged reference peak geoelectric field amplitude, the Commission should:

> allow NERC to further determine the appropriate localized studies to be performed by moving the "local hot spot" around a planning area. This approach may better ensure that the peak values only impact a local area instead of unrealistically projecting uniform peak values over a broad area. This approach also should better align with the Commission's concerns because this type of study would more accurately reflect the real-world impact of a GMD event on the [Bulk-Power System]. The Trade

[52] Trade Associations Comments at 15.

[53] *Id.* at 17 (quoting 2015 Pulkkinen Paper at 6).

> Associations understand that existing planning tools may not yet have such capabilities, but the tools can be modified to allow such study.[54]

40. Industry commenters raise other concerns with the NOPR proposal. CEA states that it would be inappropriate to rely on the non-spatially averaged 20 V/km reference peak geoelectric field figure because that figure is found in a single publication. CEA also contends that it is impractical to use "engineering judgment" to weigh the GMD Vulnerability Assessments using the spatially-averaged and non-spatially averaged reference peak geoelectric field amplitudes, as described in the NOPR.[55] ITC states that NERC's proposal is reasonable and that the reference peak geoelectric field amplitude value can be revised periodically based on new information. Joint ISOs/RTOs state that the Commission should afford due weight to NERC's technical expertise.

41. A September 2015 paper prepared by the Los Alamos National Laboratory states that it analyzed the IMAGE data using a different methodology to calculate reference peak geoelectric field amplitude values based on each of eight different magnetometer installations in Northern Europe. However, unlike the standard drafting team, the Los Alamos Paper did not spatially average the IMAGE data. The authors calculated peak geoelectric field amplitudes ranging from 8.4 V/km to 16.6 V/km, with a mean of

[54] *Id.* at 16.

[55] *See also* Hydro One Comments at 1-2; Resilient Societies Comments at 24-25.

the eight values equal to 13.2 V/km.[56] The authors used a statistical formula and probability distribution to determine their 1-in-100 year GMD event parameters, as opposed to the 20 V/km non-spatially averaged event from the 2012 paper cited in the GMD Interim Report that visually extrapolated the data.

42. Roodman contends that "NERC's 100-year benchmark GMD event is appropriately conservative in magnitude (except perhaps in the southern-most US) if unrealistic in some other respects."[57] Roodman states that "overall NERC's analytical frame does not strongly clash with the data."[58] However, Roodman contends that actual data support local hot-spots in a larger region of lower magnitude geoelectric fields that are not typically uniform in magnitude or direction.[59] Roodman addresses comments by Kappenman against the benchmark GMD event by stating that the Oak Ridge Report's Meta-R-319 study, authored by Kappenman, modeled a 1-in-100 year GMD event based largely on misunderstandings of historic GMDs, both in magnitude and geographic

[56] Rivera, M., Backhaus, S., "Review of the GMD Benchmark Event in TPL-007-1," Los Alamos National Laboratory (September 2015) (Los Alamos Paper).

[57] Roodman Comments at 4. Roodman criticizes the proposed benchmark GMD event definition because it assumes that the induced electrical field resulting from a GMD event is spatially uniform. Roodman also contends that a GMD event that is less than a 1-in-100 year storm could potentially damage transformers. *Id.* at 12-14.

[58] Roodman Comments at 9.

[59] *Id.* at 10, 12-13.

footprint.[60] Roodman recommends that the Commission "require a much larger array of events for simulation" in light of the "deep uncertainty and complexity of the GMD."[61]

43. Commenters opposed to the benchmark GMD event definition proposed by NERC maintain that the standard drafting team significantly underestimated the reference peak geoelectric field amplitude value for a 1-in-100 year GMD event by relying on data from the IMAGE system and by applying spatial averaging to that data set.[62] For example, Resilient Societies states that the standard drafting team should have analyzed "real-world data from within the United States and Canada, including magnetometer readings from the [USGS] and Natural Resources Canada observatories … [h]ad NERC and the Standard Drafting Team collected and analyzed available real-world data, they would have likely found that the severity of GMD in 1-in-100 Year reference storm had been set far below a technically justified level and without a 'strong technical basis.'"[63] Likewise, Kappenman contends that there are multiple examples where the benchmark GMD event and the standard drafting team's model for calculating geoelectric fields under-predict

[60] *Id.* at 5-6 (citing Oak Ridge National Laboratory, Geomagnetic Storms and Their Impacts on the U.S. Power Grid: Meta-R-319 at pages I-1 to I-3 (January 2010), http://www.ornl.gov/sci/ees/etsd/pes/pubs/ferc_Meta-R-319.pdf (Meta-R-319 Study).

[61] *Id.* at 15.

[62] *See, e.g.*, JINSA Comments at 2; Emprimus Comments at 1. *See also* Gaunt Comments at 9 (indicating that the proposed benchmark GMD event definition may underestimate the effects of a 1-in-100 GMD event).

[63] Resilient Societies Comments at 20-21.

actual, historical GIC readings.[64] Commenters opposed to NERC's proposal variously argue that the reference peak geoelectric field amplitude should be set at a level commensurate with the 1921 Railroad Storm or 1859 Carrington Event or at the 20 V/km level cited in the GMD Interim Report.[65]

Commission Determination

44. The Commission approves the reference peak geoelectric field amplitude figure proposed by NERC. In addition, the Commission, as proposed in the NOPR, directs NERC to develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data. The Commission directs NERC to submit this revision within 18 months of the effective date of this Final Rule.

45. NERC and industry comments do not contain new information to support relying solely on spatially-averaged data to calculate the reference peak geoelectric field amplitude in the benchmark GMD event definition. The 2015 Pulkkinen Paper contains the same justifications for spatial averaging as those presented in NERC's petition. In addition, the 2015 Pulkkinen Paper validates the NOPR's concerns with relying solely on

[64] Kappenman Comments at 15- 29.

[65] *See*, *e.g.*, EIS Comments at 2 (advocating use of 20 V/km); Gaunt Comments at 6-9 (contending that NERC's proposed figure results in a "possible underestimation of the effects of GICs" without suggesting an alternative figure); JINSA Comments at 2 (advocating use of 20 V/km); Emprimus Comments at 1 (advocating use of 20 V/km); Briggs Comments at 1 (advocating that the benchmark GMD event should be a "Carrington Class solar superstorm").

spatial averaging generally and with the method used by the standard drafting team to spatially average the IMAGE data specifically. The 2015 Pulkkinen Paper, for example, states that "regional scale geoelectric fields have not been considered earlier from the statistical and extreme analyses standpoint" and "selection of an area of 500 km [for spatial averaging] …[is] subjective."[66] Further, the 2015 Pulkkinen Paper notes that "we emphasize that the work described in this paper is only the beginning in our exploration of spatial geoelectric field structures pertaining to extreme GIC … [and] [w]e will … expand the statistical analyses to include characterization of multiple different spatial scales."[67] On the latter point, NERC "agrees that such research would provide additional modeling insights and supports further collaborative efforts between space weather researchers and electric utilities through the NERC GMD Task Force."[68] These statements support the NOPR's observation that the use of spatial averaging in this context is new, and thus there is a dearth of information or research regarding its application or appropriate scale.

46. While we believe our directive addresses concerns with relying solely on spatially-averaged data, we reiterate the position expressed in the NOPR that a GMD event will have a peak value in one or more location(s) and the amplitude will decline over distance

[66] 2015 Pulkkinen Paper at 2.

[67] *Id.* at 6.

[68] NERC Comments at 8.

from the peak; and, as a result, imputing the highest peak geoelectric field value in a planning area to the entire planning area may incorrectly overestimate GMD impacts.[69] Accordingly, our directive should not be construed to prohibit the use of spatial averaging in some capacity, particularly if more research results in a better understanding of how spatial averaging can be used to reflect actual GMD events.

47. The NOPR proposed to direct NERC to revise Reliability Standard TPL-007-1 so that the reference peak geoelectric field value is not based solely on spatially-averaged data. NERC and industry comments largely focused on the NOPR's discussion of one possible example to address the directive (i.e., by running GMD Vulnerability Assessments using spatially-averaged and non-spatially averaged reference peak geoelectric field amplitudes). However, while the method discussed in the NOPR is one possible option, the NOPR did not propose to direct NERC to develop revisions based on that option or any specific option. The Trade Associations' comments, discussed above, demonstrate that there is another way to address the NOPR directive (i.e., by performing planning models that also assess planning areas for localized "hot spots"). This approach may have merit if, for example, the geographic size of the hot spot is supported by actual data and the hot spot is centered over one or more locations that include an entity's facilities that become critical during a GMD event. Without pre-judging how NERC proposes to address the Commission's directive, NERC's response to this directive

[69] NOPR, 151 FERC ¶ 61,134 at P 35.

should satisfy the NOPR's concern that reliance on spatially-averaged data alone does not address localized peaks that could potentially affect the reliable operation of the Bulk-Power System.

48. We believe our directive should also largely address the comments submitted by entities opposed to NERC's proposed reference peak geoelectric field amplitude. Those commenters endorsed using a higher reference peak geoelectric field amplitude value, such as the 20 V/km cited in the GMD Interim Report. At the outset, we observe that the comments critical of the standard drafting team's use of the IMAGE data only speculate that had the standard drafting team used other sources, the calculated reference peak geoelectric field amplitude value would have been higher.[70] Moreover, among the commenters critical of NERC's proposal, there is disagreement over the magnitude of historical storms which some of these commenters would use as a model.[71] While NERC has discretion on how to propose to address our directive, NERC could revise Reliability Standard TPL-007-1 to apply a higher reference peak geoelectric field amplitude value to assess the impact of localized hot spots on the Bulk-Power System, as suggested by the

[70] *See, e.g.,* Resilient Societies Comments at 21 ("Had NERC and the Standard Drafting Team collected and analyzed available real-world data, they *would have likely found* that the severity of GMD in 1-in-100 Year reference storm had been set far below a technically justified level …" (emphasis added)).

[71] *See, e.g.,* Gaunt Comments at 13 (stating that the 1859 Carrington Event is "probably outside the re-occurrence frequency of 1:100 years adopted by NERC for the benchmark event"); Briggs Comments at 1 (advocating using a "'Carrington Class' super storm" as the benchmark GMD event).

Trade Associations. The effects of such hot spots could include increases in GIC levels, volt-ampere reactive power consumption, harmonics on the Bulk-Power System (and associated misoperations) and transformer heating. Moreover, the directive to revise Reliability Standard TPL-007-1 and, as discussed below, the directives to research geomagnetic latitude scaling factors and earth conductivity models as part of the GMD research work plan and to revise Reliability Standard TPL-007-1 to require the collection of necessary GIC monitoring and magnetometer data to validate GMD models should largely address or at least help to focus-in on factors that may be causing any inaccuracies in the standard drafting team's model.

49. Consistent with Order No. 779, the Commission does not specify a particular reference peak geoelectric field amplitude value that should be applied to hot spots given present uncertainties. While 20 V/km would seem to be a possible value, the Los Alamos Paper suggests that the 20 V/km figure may be too high. The Los Alamos Paper analyzed the non-spatially averaged IMAGE data to calculate a reference peak geoelectric field amplitude range (i.e., 8.4 V/km to 16.6 V/km) that is between NERC's proposed spatially-averaged value of 8 V/km and the non-spatially averaged 20 V/km figure cited in the GMD Interim Report.

50. Although the NOPR did not propose to direct NERC to submit revisions to Reliability Standard TPL-007-1 by a certain date with respect to the benchmark GMD event definition, the Commission determines that it is appropriate to impose an 18-month deadline from the effective date of this Final Rule. As discussed below, the Commission approves the five-year implementation period for Reliability Standard TPL-007-1

proposed by NERC. Having NERC submit revisions to the benchmark GMD event definition within 18 months of the effective date of this Final Rule, with the Commission acting promptly on the revised Reliability Standard, should afford enough time to apply the revised benchmark GMD event definition in the first GMD Vulnerability Assessment under the timeline set forth in Reliability Standard TPL-007-1's implementation plan. If circumstances, such as the complexity of the revised benchmark GMD event, require it, NERC may propose and justify a revised implementation plan.

2. Geomagnetic Latitude Scaling Factor

NOPR

51. The NOPR proposed to approve the geomagnetic latitude scaling factor in NERC's proposed benchmark GMD event definition. However, the NOPR sought comment on whether, in light of studies indicating that GMD events could have pronounced effects on lower geomagnetic latitudes, a modification is warranted to reduce the impact of the scaling factors.[72]

[72] NOPR, 151 FERC ¶ 61,134 at P 37 (citing Ngwira, C. M., Pulkkinen, A., Kuznetsova, M. M., Glocer, A., "Modeling extreme 'Carrington-type' space weather events using three-dimensional global MHD simulations," 119 Journal of Geophysical Research: Space Physics 4472 (2014) (finding that in Carrington-type events "the region of large induced ground electric fields is displaced further equatorward … [and] thereby may affect power grids … such as [those in] southern states of [the] continental U.S."); Gaunt, C. T., Coetzee, G., "Transformer Failures in Regions Incorrectly Considered to have Low GIC-Risk," 2007 IEEE Lausanne 807 (July 2007) (stating that twelve transformers were damaged and taken out of service in South Africa (at -40 degrees latitude) during the October 2003 Halloween Storm GMD event)). *See also* Liu, C., Li, Y., Pirjola, R., "Observations and modeling of GIC in the Chinese large-scale high-voltage power networks," Journal Space Weather Space Climate 4 at A03-p6 (2014) (Liu

(continued…)

Comments

52. NERC contends that the geomagnetic latitude scaling factor in Reliability Standard TPL-007-1 "accurately models the reduction of induced geoelectric fields that occurs over the mid-latitude region during a 100-year GMD event scenario … [and] describes the observed drop in geoelectric field that has been exhibited in analysis of major recorded geomagnetic storms."[73] NERC maintains that modifying the scaling factor is not technically justified based on the publications cited in the NOPR. NERC states that the first paper cited in the NOPR is based on models that are not mature and reflect a 1-in-150 year storm. NERC contends that the second paper does not clearly show that the purported transformer damage in South Africa was the result of abnormally high GICs during the October 2003 Halloween Storm. NERC further states that the standard drafting team analyzed the October 2003 Halloween Storm when developing the proposed geomagnetic latitude scaling factor.

53. The Trade Associations support the geomagnetic latitude scaling factor proposed by NERC. Like NERC, the Trade Associations contend that the papers cited in the NOPR do not support modifications because the models in the first paper "remain highly

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Paper), http://www.swsc-journal.org/articles/swsc/pdf/2014/01/ swsc130009.pdf (finding that GICs of about 25A/phase had been measured in a transformer at a nuclear power plant at 22.6 degrees north latitude (significantly further away from the magnetic pole than Florida)).

[73] NERC Comments at 9 (citing Ngwira, C., Pulkkinen, A., Wilder, F., Crowley, G., "Extended Study of Extreme Geoelectric Field Event Scenarios for Geomagnetically Induced Current Applications," 11 Space Weather 121 (2013) (Ngwira 2013 Paper)).

theoretical and not sufficiently validated" and because the second paper likely involved other causal factors leading to the transformer failure.[74] Joint ISOs/RTOs also support the geomagnetic latitude scaling factor proposed by NERC. ITC states that NERC's proposal is a "reasonable approach given the current state of the science pertaining to GMD … [but] that as the science pertaining to GMD matures and more data becomes available, the scaling factors should be revisited and revised."[75] ITC suggests revisiting the geomagnetic latitude scaling factor every five years to incorporate any new developments in GMD science.

54. Several commenters question or disagree with the geomagnetic latitude scaling factors in Reliability Standard TPL-007-1 based on simulations and reports of damage to transformers in areas expected to be at low risk due to their geomagnetic latitude.[76] EIS contends that the proposed geomagnetic latitude scaling factor's assumption of a storm centered at 60 degrees geomagnetic latitude is inconsistent with a study relied upon by NERC.[77] The Los Alamos Paper's analysis suggests that NERC's proposed geomagnetic latitude scaling factors, while they fit well with weaker historical GMD events from

[74] Trade Associations Comments at 18-19.

[75] Joint ISOs/RTOs Comments at 5.

[76] *See, e.g.*, Gaunt Comments at 6; JINSA Comments at 2; Emprimus Comments at 2-3; Roodman Comments at 9; Resilient Societies Comments at 31-31; Kappenman Comments at 41-42.

[77] EIS Comments at 5 (citing Ngwira 2013 Paper).

which they were derived, may not accurately represent the effects of a 1-in-100 year GMD event at lower geomagnetic latitudes. The Los Alamos Paper states that a model of the electrojet is needed to "effectively extrapolate the small to moderate disturbance data currently in the historical record to disturbances as large as the TPL-007-1 Benchmark Event."[78] The Los Alamos Paper uses a larger number of geomagnetic disturbances (122 instead of 12) and a wider range of observatories by using the world-wide SuperMAG magnetometer array data, which includes the INTERMAGNET data used to support NERC's geomagnetic latitude scaling factors. The Los Alamos Paper shows that for more severe storms (Dst < -300, for which there are nine storms in the data set) the NERC scaling factors tend to be low, off by a factor of up to two or three at some latitudes. The Los Alamos Paper also recommends "an additional degree of conservatism in the mid-geomagnetic latitudes" until such time as a model is developed.[79] The Los Alamos Paper authors recommend a factor of 2 as a conservative correction.

Commission Determination

55. The Commission approves the geomagnetic latitude scaling factor in the benchmark GMD event definition. In addition, the Commission directs NERC to conduct further research on geomagnetic latitude scaling factors as part of the GMD research work plan discussed below.

[78] Los Alamos Paper at 12.

[79] *Id.*

56. Based on the record, the Commission finds sufficient evidence to conclude that lower geomagnetic latitudes are, to some degree, less susceptible to the effects of GMD events. The issue identified in the NOPR and by some commenters focused on the specific scaling factors in Reliability Standard TPL-007-1 in light of some analyses and anecdotal evidence suggesting that lower geomagnetic latitudes may be impacted by GMDs to a larger degree than reflected in Reliability Standard TPL-007-1.

57. The geomagnetic latitude scaling factor in Reliability Standard TPL-007-1 is supported by some of the available research.[80] In addition, with the exception of the Los Alamos Paper, commenters did not provide new information on the proposed scaling factor nor did commenters suggest alternative scaling factors. However, the Commission finds that there are enough questions regarding the effects of GMDs at lower geomagnetic latitudes to warrant directing NERC to study this issue further as part of the GMD research work plan. The Los Alamos Paper and the sources cited in the NOPR are suggestive that a 1-in-100 year GMD event could have a greater impact on lower

[80] *See* NERC Comments at 9 (citing Ngwira 2013 Paper). We disagree with the contention made by EIS that NERC's proposed geomagnetic latitude scaling factors are inconsistent with the Ngwira 2013 Paper. EIS maintains that the Ngwira 2013 Paper supports the conclusion that the benchmark GMD event should be centered at 50 degrees geomagnetic latitude instead of the 60 degree geomagnetic latitude figure in Reliability Standard TPL-007-1. The Ngwira 2013 Paper contains no such conclusion. Instead, the Ngwira 2013 Paper found that the latitude threshold boundary is a transition region having a definite lower bound of 50 degrees geomagnetic latitude but with an upper range as high as 55 degrees geomagnetic latitude. Ngwira 2013 Paper at 127, 130. The Ngwira 2013 Paper also stated that its findings were "in agreement with earlier observations by [Thomson et al., 2011] and more recently by [Pulkkinen et al., 2012], which estimated the location to be within 50 [degrees]–62 [degrees]." *Id.* at 124.

geomagnetic latitudes than NERC's proposed scaling factor assumes. But, as the Los Alamos Paper recognizes, the current absence of historical data on large GMD events precludes a definitive conclusion based on an empirical analysis of historical observations. Moreover, in prepared comments for the March 1, 2016 Technical Conference, Dr. Backhaus, one of the authors of the Los Alamos Paper, recommended that "the current NERC analysis should be adopted and further analysis performed with additional observational data and severe disturbance modeling efforts with the intent of refining the geomagnetic latitude scaling law in future revisions."[81] The Commission directs NERC to reexamine the geomagnetic latitude scaling factors in Reliability Standard TPL-007-1 as part of the GMD research work plan, including using existing models and developing new models to extrapolate from historical data on small to moderate GMD events the impacts of a large, 1-in-100 year GMD event on lower geomagnetic latitudes.

B. Thermal Impact Assessments

NERC Petition

58. Reliability Standard TPL-007-1, Requirement R6 requires owners of transformers that are subject to the Reliability Standard to conduct thermal analyses to determine if the transformers would be able to withstand the thermal effects associated with a benchmark GMD event. NERC states that transformers are exempt from the thermal impact

[81] Statement of Scott Backhaus, March 1, 2016 Technical Conference at 2.

assessment requirement if the maximum effective GIC in the transformer is less than 75 A/phase during the benchmark GMD event as determined by an analysis of the system. NERC explains that "based on available power transformer measurement data, transformers with an effective GIC of less than 75 A/phase during the Benchmark GMD Event are unlikely to exceed known temperature limits established by technical organizations."[82]

59. As provided in Requirements R5 and R6, "the maximum GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1" determines whether a transformer satisfies the 75 A/phase threshold. If the 75 A/phase threshold is satisfied, Requirement R6 states, in relevant part, that a thermal impact assessment should be conducted on the qualifying transformer based on the effective GIC flow information provided in Requirement R5.

60. In its June 28, 2016 filing, NERC states that it identified an error in Figure 1 (Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event) of the White Paper on Screening Criterion for Transformer Thermal Impact Assessment that resulted in incorrect plotting of simulated power transformer peak hot-spot heating from the benchmark GMD event. NERC revised Figure 1 in the White Paper on Screening Criterion for Transformer Thermal Impact Assessment and made corresponding revisions to related text, figures and tables throughout the technical white

[82] NERC Petition at 30.

papers supporting the proposed standard. NERC maintains that even with the revision to Figure 1, "the standard drafting team determined that the 75 A per phase threshold for transformer thermal impact assessment remains a valid criterion … [and] it is not necessary to revise any Requirements of the proposed Reliability Standard."[83]

NOPR

61. The NOPR proposed to approve the transformer thermal impact assessments in Requirement R6. In addition, as with the benchmark GMD event definition, the NOPR proposed to direct NERC to revise Requirement R6 to require registered entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments. The NOPR also noted that Requirement R6 does not use the maximum GIC-producing orientation to conduct the thermal assessment for qualifying transformers; instead, the requirement uses the effective GIC time series described in Requirement R5.2 to conduct the thermal assessment on qualifying transformers. The NOPR sought comment from NERC as to why qualifying transformers are not assessed for thermal impacts using the maximum GIC-producing orientation and directed NERC to address whether, by not using the maximum GIC-producing orientation, the required thermal impact assessments could underestimate the impact of a benchmark GMD event on a qualifying transformer.

[83] NERC June 28, 2016 Filing at 1.

Comments

62. NERC opposes modifying the thermal impact assessments in Requirement R6 so that the assessments do not rely only on spatially-averaged data. NERC claims that the benchmark GMD event definition will "result in GIC calculations that are appropriately scaled for system-wide assessments."[84] NERC also contends that the "analysis performed by the standard drafting team of the impact of localized enhanced geoelectric fields on the GIC levels in transformers indicates that relatively few transformers in the system are affected."[85] In response to the question in the NOPR of why qualifying transformers are not assessed for thermal impacts using the maximum GIC producing orientation, NERC states that "the orientation of the geomagnetic field varies widely and continuously during a GMD event … [and] would be aligned with the maximum GIC-producing orientation for only a few minutes."[86] NERC concludes that "[i]n the context of transformer hot spot heating with time constants in the order of tens of minutes, alignment with any particular orientation for a few minutes at a particular point in time is not a driving concern."[87] NERC further states that the wave shape used in Reliability

[84] NERC Comments at 17.

[85] *Id.*

[86] *Id.* at 19.

[87] *Id.*

Standard TPL-007-1 provides "generally conservative results when performing thermal analysis of power transformers."[88]

63. The Trade Associations and CEA do not support the proposed NOPR directive because, they state, it focuses too heavily on individual transformers. The Trade Associations maintain that Reliability Standard TPL-007-1 "was never intended to address specific localized areas that might experience peak conditions and affect what we understand to be a very small number of assets that are unlikely to initiate a cascading outage."[89]

64. Certain non-industry commenters contend that the 75 A/phase qualifying threshold for thermal impact assessments is not technically justified. Emprimus contends that "many transformers have GIC ratings less than 75 amps per phase," but Emprimus claims that an Idaho National Lab study showed that "GIC introduced at 10 amps per phase on high voltage transformers exceed harmonic levels allowed under IEEE 519."[90] Emprimus also maintains that a 2013 IEEE paper "suggest[s] that there can be generator rotor damage at GIC levels which exceed 50 amps per phase."[91] Gaunt contends, based on his analysis of historical events, that "degradation is initiated in transformers by

[88] *Id.*

[89] Trade Associations Comments at 21.

[90] Emprimus Comments at 4.

[91] *Id.*

currents that are significantly below the 75 amps per phase."[92] Gaunt states that "[u]ntil better records are kept of transformer [dissolved gas in oil analysis] and transformer failure, the proposed level of 75 [A/phase] of GIC needed to initiate assessment of transformer response must be considered excessively high."[93] Gaunt recommends a qualifying threshold of 15 amps per phase. Resilient Societies states that the 75 A/phase threshold is based on a mathematical model for one type of transformer and that several tests referenced in the standard drafting team's White Paper on Transformer Thermal Impact Assessment were carried out under no load or minimal load conditions. In addition, Resilient Societies contends that applying the 75 A/phase threshold and NERC's proposed benchmark GMD event (i.e., using the spatially-averaged reference peak geoelectric field amplitude) results in only "two out of approximately 560 extra high voltage transformers" requiring thermal impact assessments in the PJM region; only one 345 kV transformer requiring thermal impact assessment in Maine; and zero transformers requiring thermal impact assessments in ATC's network.[94] Kappenman contends that the

[92] Gaunt Comments at 13.

[93] *Id.* at 14.

[94] Resilient Societies Comments at 5-14. Resilient Societies states that modeling performed by Central Maine Power Co. and Emprimus for the Maine Public Utilities Commission indicates that eight 345 kV transformers (53 percent according to Resilient Societies) would require thermal impact assessments in Maine if the reference peak geoelectric field amplitude were set at 20 V/km. *Id.* at 10. Resilient Societies also contends that this result is consistent with the Oak Ridge Meta-R-319 Study's finding that eight transformers would be "at risk" in Maine under a "'30 Amp At-Risk Threshold scenario.'" *Id.* Central Maine Power Co. calculated that the scaled NERC benchmark

(continued…)

75 A/phase threshold does not consider transformers with tertiary windings or autotransformers which may be impacted at lower GIC levels than 75 A/phase.[95]

Commission Determination

65. Consistent with our determination above regarding the reference peak geoelectric field amplitude value, the Commission directs NERC to revise Requirement R6 to require registered entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments.

66. In the NOPR, the Commission requested comment from NERC regarding why Requirement R6 does not use the maximum GIC-producing orientation to conduct the thermal assessment for qualifying transformers. After considering NERC's response, we continue to have concerns with not using the maximum GIC-producing orientation for the thermal assessment of transformers. However, at this time we do not direct NERC to modify Reliability Standard TPL-007-1. Instead, as part of the GMD research work plan discussed below, NERC is directed to study this issue to determine how the geoelectric field time series can be applied to a particular transformer so that the orientation of the

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GMD event for the northernmost point in Maine would be 4.53 V/km. Resilient Societies' calculations regarding ATC estimate that the scaled benchmark GMD event for Wisconsin would be 2 V/km. *Id.* at 14.

[95] The Commission received two comments following NERC's June 28, 2016 Filing. However, the supplemental comments did not specifically address the revisions submitted in NERC's June 28, 2016 filing.

time series, over time, will maximize GIC flow in the transformer, and to include the results in a filing with the Commission.

67. We are not persuaded by the comments opposed to Requirement R6's application of a 75 A/phase qualifying threshold. The standard drafting team's White Paper on Thermal Screening Criterion, as revised by NERC in the June 28, 2016 Filing, provides an adequate technical basis to approve NERC's proposal. As noted in the revised White Paper on Thermal Screening Criterion, the calculated metallic hot spot temperature corresponding to an effective GIC of 75 A/phase is 172 degrees Celsius; that figure is higher than the original figure of 150 degrees Celsius calculated by the standard drafting team but is still below the 200 degree Celsius limit specified in IEEE Std C57.91-2011.[96] The comments, particularly those of Gaunt, attempt to correlate historical transformer failures to past GMD events (e.g., 2003 Halloween Storm), while arguing that the transformers damaged in those events did not experience GICs of 75 A/phase. The evidence adduced by Gaunt and others is inconclusive.[97] We therefore direct NERC to include further analysis of the thermal impact assessment qualifying threshold in the GMD research work plan.

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[96] NERC June 28, 2016 Filing, Revised White Paper on Screening Criterion for Transformer Thermal Impact Assessment at 3.

[97] *See, e.g.,* Gaunt Comments at 13 ("Although it has not been possible to assemble an exact model of the power system during the period 29-31 October 2003, and data on the ground conductivity in Southern Africa is not known with great certainty, we are confident that the several calculations of GIC that been carried out are not grossly inaccurate.").

68. In NOPR comments and in comments to the standard drafting team, Kappenman stated that delta winding heating due to harmonics has not been adequately considered by the standard drafting team and that, thermally, this is a bigger concern than metallic hot spot heating.[98] The standard drafting team responded that the vulnerability described for tertiary winding harmonic heating is based on the assumption that delta winding currents can be calculated using the turns ratio between primary and tertiary winding, which is incorrect when a transformer is under saturation.[99] The standard drafting team concluded that Kappenman's concerns regarding delta windings being a problem from a thermal standpoint are unwarranted and that the criteria developed by the standard drafting team use state-of-the-art analysis methods and measurement-supported transformer models. The Commission believes that the heating effects of harmonics on transformers, as discussed at the March 1, 2016 Technical Conference, are of concern and require further research.[100] Accordingly, we direct NERC to address the effects of harmonics, including

[98] Kappenman Comments at 45.

[99] Consideration of Comments Project 2013-03 Geomagnetic Disturbance Mitigation at 39 (December 5, 2014), http://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/Comment%20Report%20_2013-03_GMD_12052014.pdf.

[100] At the March 1, 2016 Technical Conference, Dr. Horton, a member of the standard drafting team, discussed the potential negative impacts of harmonics generated by GMDs on protection systems, reactive power resources and generators. Slide Presentation of Randy Horton, March 1, 2016 Technical Conference at 2-6.

tertiary winding harmonic heating and any other effects on transformers, as part of the GMD research work plan.[101]

C. GMD Research Work Plan

NOPR

69. The NOPR proposed to address the need for more data and certainty regarding GMD events and their potential effect on the Bulk-Power System by directing NERC to submit informational filings that address GMD-related research areas. The NOPR proposed to direct NERC to submit in the first filing a GMD research work plan indicating how NERC plans to: (1) further analyze the area over which spatial averaging should be calculated for stability studies, including performing sensitivity analyses on squares less than 500 km per side (e.g., 100 km, 200 km); (2) further analyze earth conductivity models by, for example, using metered GIC and magnetometer readings to calculate earth conductivity and using 3-D readings; (3) determine whether new analyses and observations support modifying the use of single station readings around the earth to adjust the spatially averaged benchmark for latitude; and (4) assess how to make GMD data (e.g., GIC monitoring and magnetometer data) available to researchers for study.

70. With respect to GIC monitoring and magnetometer readings, the NOPR sought comment on the barriers, if any, to public dissemination of such readings, including if

[101] NERC indicated in its comments that it is already studying the issue of harmonics. NERC Comments at 14 ("NERC is collaborating with researchers to examine more complex GMD vulnerability issues, such as harmonics and mitigation assessment techniques, to enhance the modeling capabilities of the industry").

their dissemination poses a security risk and if any such data should be treated as Critical Energy Infrastructure Information or otherwise restricted to authorized users. The NOPR proposed that NERC submit the GMD research work plan within six months of the effective date of a final rule in this proceeding. The NOPR also proposed that the GMD research work plan submitted by NERC should include a schedule for submitting one or more informational filings that apprise the Commission of the results of the four additional study areas, as well as any other relevant developments in GMD research, and should assess whether Reliability Standard TPL-007-1 remains valid in light of new information or whether revisions are appropriate.

Comments

71. NERC states that continued GMD research is necessary and that the potential impacts of GMDs on reliability are evolving. NERC, however, prefers that the NERC GMD Task Force continue its research without the GMD research work plan proposed in the NOPR. NERC contends that allowing the NERC GMD Task Force to continue its work would "accomplish NERC's and the Commission's shared goals in advancing GMD understanding and knowledge, while providing the flexibility necessary for NERC to work effectively with its international research partners to address risks to the reliability of the North American Bulk-Power System."[102] NERC also claims that, in addition to being unnecessary given the work of the NERC GMD Task Force, the NOPR

[102] NERC Comments at 13.

proposal "poses practical challenges … [because it would] bind[] NERC to a specific and inflexible research plan and report schedule to be determined six months (or even a year) following the effective date of a final rule in this proceeding."[103]

72. The Trade Associations and CEA do not support the GMD research work plan. Instead, they contend that NERC should be allowed to pursue GMD research independently.

73. Several commenters, while not addressing the NOPR proposal specifically, state that additional research is necessary to validate or improve elements of the benchmark GMD event definition.[104]

74. The Trade Associations state that monitoring data should be available for academic research purposes. Resilient Societies contends that monitoring data should be publicly disseminated on a regular basis and that there is no security risk in releasing such data because they relate to naturally occurring phenomena. Emprimus states that it supports making GIC and magnetometer monitoring data available to the public. Bardin supports making GIC and GMD-related information to the public or at least to "legitimate researchers."

[103] *Id.* at 16.

[104] *See, e.g.*, USGS Comments at 1 (addressing earth conductivity models), Bardin Comments at 2 (addressing earth conductivity models); Roodman Comments at 3 (addressing reference peak geoelectric field amplitude); Gaunt Comments at 7 (addressing spatial averaging).

75. Hydro One and CEA do not support mandatory data sharing without the use of non-disclosure agreements.

Commission Determination

76. The Commission recognizes, as do commenters both supporting and opposing proposed Reliability Standard TPL-007-1, that our collective understanding of the threats posed by GMD is evolving as additional research and analysis are conducted. These ongoing efforts are critical to the nation's long-term efforts to protect the grid against a major GMD event. While we approve NERC's proposed Reliability Standard TPL-007-1 and direct certain modifications, as described above, the Commission also concludes that facilitating additional research and analysis is necessary to adequately address these threats. As discussed in the next two sections of this final rule, the Commission directs a three-prong approach to further those efforts by directing NERC to: (1) develop, submit, and implement a GMD research work plan; (2) develop revisions to Reliability Standard TPL-007-1 to require responsible entities to collect GIC monitoring and magnetometer data; and (3) collect GIC monitoring and magnetometer data from registered entities for the period beginning May 2013, including both data existing as of the date of this order and new data going forward, and to make that information available.

77. First, the Commission adopts the NOPR proposal and directs NERC to submit a GMD research work plan and, subsequently, informational filings that address the GMD-related research areas identified in the NOPR, additional research tasks identified in this Final Rule (i.e., the research tasks identified in the thermal impact assessment discussion above) and, in NERC's discretion, any GMD-related research areas generally that may

impact the development of new or modified GMD Reliability Standards.[105] The GMD research work plan should be submitted within six months of the effective date of this final rule. The research required by this directive should be informed by ongoing GMD-related research efforts of entities such as USGS, National Atmospheric and Oceanic Administration (NOAA), National Aeronautics and Space Administration, Department of Energy, academia and other publicly available contributors, including work performed for the National Space Weather Action Plan.[106]

78. As part of the second research area identified in the NOPR (i.e., further analyze earth conductivity models by, for example, using metered GIC and magnetometer readings to calculate earth conductivity and using 3-D readings), the GMD research work plan should specifically investigate "coastal effects" on ground conductivity models.

79. In addition, the large variances described by USGS in actual 3-D ground conductivity data raise the question of whether one time series geomagnetic field is sufficient for vulnerability assessments. The characteristics, including frequencies, of the time series interact with the ground conductivity to produce the geoelectric field that

[105] The GMD research work plan need not address the fourth research area identified in the NOPR (i.e., assess how to make GIC monitoring and magnetometer data available to researchers for study) given the Commission's directive and discussion below regarding the collection and dissemination of necessary GIC monitoring and magnetometer data.

[106] National Science and Technology Council, National Space Weather Action Plan (October 2015), https://www.whitehouse.gov/sites/default/files/microsites/ostp/final_nationalspaceweatheractionplan_20151028.pdf.

drives the GIC. Therefore, the research should address whether additional realistic time series should be selected to perform assessments in order to capture the time series that produces the most vulnerability for an area.

80. The comments largely agree that additional GMD research should be pursued, particularly with respect to the elements of the benchmark GMD event definition (i.e., the reference peak geoelectric field amplitude value, geomagnetic latitude scaling factor, and earth conductivity scaling factor). There is ample evidence in the record to support the need for additional GMD-related research.[107] For example, USGS submitted comments indicating that USGS's one dimensional ground electrical conductivity models used by the standard drafting team have a "significant limitation" in that they assume that a "[one dimensional] conductivity-with-depth profile can adequately represent a large geographic region," which USGS describes as a "gross simplification."[108] USGS observes that while the "proposed standard attempted to incorporate the best scientific research available … it must be noted that the supporting science is quickly evolving."[109] USGS recommends that "the proposed standard should establish a process for updates and improvements that

[107] *See, e.g.*, NERC October 22, 2015 Supplemental Comments at 7-8 (expressing support for additional research regarding geomagnetic latitude scaling factors and earth conductivity models).

[108] USGS Comments at 1.

[109] *Id.*

acknowledges and addresses the quickly evolving nature of relevant science and associated data."[110]

81. Opposition to the proposal centers on the contention that the proposed directive is unnecessary and potentially counterproductive given the continuing work of the NERC GMD Task Force. We do not find these comments persuasive. Our directive requires NERC to submit a work plan for the study of GMD-related issues that are already being examined or that NERC agrees should be studied.[111] Nothing in our directive precludes NERC from continuing to use the NERC GMD Task Force as a vehicle for conducting the directed research or other research. Indeed, we encourage NERC to continue to use

[110] *Id.* We note that Reliability Standard TPL-007-1, Att. 1 (Calculating Geoelectric Fields for the Benchmark GMD Event) already provides that a "planner can also use specific earth model(s) with documented justification…" Accordingly, Reliability Standard TPL-007-1 includes a mechanism for incorporating improvements in earth conductivity models when calculating the benchmark GMD event.

[111] *See, e.g.*, NERC Comments at 8 ("NERC agrees that [spatial averaging] research would provide additional modeling insights and supports further collaborative efforts between space weather researchers and electric utilities through the NERC GMD Task Force"), at 10 ("NERC agrees that additional [geomagnetic latitude scaling] research is necessary, and supports the significant research that is occurring throughout the space weather community to develop and validate models and simulation techniques"), at 13 ("Working with EPRI, researchers at USGS, and industry, NERC will work to improve the earth conductivity models that are a vital component to understanding the risks of GMD events in each geographic region"), and at 23 ("efforts are already underway to expand GMD monitoring capabilities … [and] [t]hrough these efforts, NERC and industry should effectively address the concerns noted by the Commission in the NOPR, including ensuring a more complete set of data for operational and planning needs and supporting analytical validation and situational awareness").

the GMD Task Force as a forum for engagement with interested stakeholders. In addition, we do not set specific deadlines for completion of the research; we only require NERC to submit the GMD research work plan within six months of the effective date of a final rule. The GMD research work plan, in turn, should include target dates for the completion of research topics and the reporting of findings to the Commission. The Commission intends to notice and invite comment on the GMD research work plan. An extension of time to submit the GMD research work plan may be available if six months proves to be insufficient. In addition, given the uncertainties commonly associated with complex research projects, the Commission will be flexible regarding changes to the tasks and target dates established in the GMD research work plan.

D. Monitoring Data

NERC Petition

82. Reliability Standard TPL-007-1, Requirement R2 requires responsible entities to "maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s)." NERC states that Reliability Standard TPL-007-1 contains "requirements to develop the models, studies, and assessments necessary to build a picture of overall GMD vulnerability and identify where mitigation measures may be necessary."[112] NERC explains that mitigating strategies "may include installation of

[112] NERC Petition at 13.

hardware (e.g., GIC blocking or monitoring devices), equipment upgrades, training, or enhanced Operating Procedures."[113]

NOPR

83. The NOPR proposed to direct NERC to revise Reliability Standard TPL-007-1 to require the installation of monitoring equipment (i.e., GIC monitors and magnetometers) to the extent there are any gaps in existing GIC monitoring and magnetometer networks. Alternatively, the NOPR sought comment on whether NERC should be responsible for installation of any additional, necessary magnetometers while affected entities would be responsible for installation of additional, necessary GIC monitors. The NOPR also proposed that, as part of NERC's work plan, NERC identify the number and location of current GIC monitors and magnetometers in the United States to assess whether there are any gaps. The NOPR sought comment on whether the Commission should adopt a policy specifically allowing recovery of costs associated with or incurred to comply with Reliability Standard TPL-007-1, including for the purchase and installation of monitoring devices.

Comments

84. NERC does not support the NOPR proposal regarding the installation of GIC monitoring devices and magnetometers. NERC contends that the proposed requirement is not necessary because Reliability Standard TPL-007-1 "supports effective GMD

[113] *Id.* at 32.

monitoring programs, and additional efforts are planned or underway to ensure adequate data for reliability purposes."[114] NERC also maintains that the proposed directive "poses implementation challenges … [because] GMD monitoring capabilities and technical information have not yet reached a level of maturity to support application in a Reliability Standard, and not all applicable entities have developed the comprehensive understanding of system vulnerabilities that would be needed to deploy GMD monitoring devices for the greatest reliability benefit."[115] NERC also notes that a requirement mandating the installation of monitoring devices for situational awareness purposes would be outside the scope of a planning Reliability Standard.

85. The Trade Associations, CEA, ITC, Hydro One and Tri-State, while agreeing that more data are useful to analytical validation and situational awareness, do not support the NOPR proposal. CEA does not support the proposal because Reliability Standard TPL-007-1 is a planning standard; a one-size-fits-all monitoring approach will not work; the responsibility for monitoring, which in Canada is done by the Canadian government, should not fall to industry or NERC; and the proposal is too costly. Likewise, ITC contends that it would not be prudent or cost effective for entities to have to install

[114] NERC Comments at 21. NERC cites as examples the 40 GIC monitoring nodes operated by EPRI's SUNBURST network; the use of GIC monitoring devices by some registered entities (e.g., PJM); and the magnetometer networks operated by USGS and EPRI. *Id.* at 23-25.

[115] *Id.*

monitoring equipment. Hydro One does not support a Reliability Standard that prescribes the number and location of monitoring devices that must be installed. The Trade Associations and ITC, instead, support directing NERC to develop a plan to address this issue. The Trade Associations state that such a plan should involve a partnership between government and industry. Tri-State maintains that NERC, working with USGS and NOAA, should be responsible for determining the need for and installation of any needed magnetometers. If the Commission requires applicable entities to install monitoring devices, the Trade Associations, Tri-State and Exelon agree that there should be cost recovery.

86. BPA supports the NOPR proposal for increased monitoring because BPA believes it will improve situational awareness. As a model, BPA states that the "Canadian government in collaboration with Canadian transmission owners" have developed a "technique that shows real promise of increasing visibility of GIC flows and localized impacts for a regional transmission grid."[116] AEP encourages the Commission to expand the "number and scope of the permanent geomagnetic observatories and install permanent geoelectric observatories in the United States."[117]

87. Resilient Societies supports requiring the installation of GIC monitoring devices and magnetometers, noting that GIC monitors are commercially available and cost as

[116] BPA Comments at 4.

[117] AEP March 29, 2016 Supplemental Comments at 1.

little as $10,000 to $15,000 each. Emprimus supports developing criteria that inform the need for and location of monitoring devices.

Commission Determination

88. We conclude that additional collection and disclosure of GIC monitoring and magnetometer data is necessary to improve our collective understanding of the threats posed by GMD events. The Commission therefore adopts the NOPR proposal in relevant part and directs NERC to develop revisions to Reliability Standard TPL-007-1 to require responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness, including from any devices that must be added to meet this need. The NERC standard drafting team should address the criteria for collecting GIC monitoring and magnetometer data discussed below and provide registered entities with sufficient guidance in terms of defining the data that must be collected, and NERC should propose in the GMD research work plan how it will determine and report on the degree to which industry is following that guidance.

89. In addition, the Commission directs NERC, pursuant to Section 1600 of the NERC Rules of Procedure, to collect GIC monitoring and magnetometer data from registered entities for the period beginning May 2013, including both data existing as of the date of this order and new data going forward, and to make that information available.[118] We also provide guidance that, as a general matter, the Commission does not believe that

[118] The Commission's directives to collect and make available GIC monitoring and magnetometer data do not apply to non-U.S. responsible entities or Alaska and Hawaii.

GIC monitoring and magnetometer data should be treated as Confidential Information pursuant to the NERC Rules of Procedure.

Collection of GIC and Magnetometer Data

90. In developing a requirement regarding the collection of magnetometer data, NERC should consider the following criteria discussed at the March 1, 2016 Technical Conference: (1) the data is sampled at a cadence of at least 10-seconds or faster; (2) the data comes from magnetometers that are physically close to GIC monitors; (3) the data comes from magnetometers that are not near sources of magnetic interference (e.g., roads and local distribution networks); and (4) data is collected from magnetometers spread across wide latitudes and longitudes and from diverse physiographic regions.[119]

91. Each responsible entity that is a transmission owner should be required to collect necessary GIC monitoring data. However, a transmission owner should be able to apply for an exemption from the GIC monitoring data collection requirement if it demonstrates that no or little value would be added to planning and operations. In developing a requirement regarding the collection of GIC monitoring data, NERC should consider the following criteria discussed at the March 1, 2016 Technical Conference: (1) the GIC data is from areas found to have high GIC based on system studies; (2) the GIC data comes from sensitive installations and key parts of the transmission grid; and (3) the data comes from GIC monitors that are not situated near transportation systems using direct current

[119] Slide Presentation of Luis Marti (Third Panel), March 1, 2016 Technical Conference at 3, 9.

(e.g., subways or light rail).[120] GIC monitoring and magnetometer locations should also be revisited after GIC system models are run with improved ground conductivity models. NERC may also propose to incorporate the GIC monitoring and magnetometer data collection requirements in a different Reliability Standard (e.g., real-time reliability monitoring and analysis capabilities as part of the TOP Reliability Standards).

92. Our determination differs from the NOPR proposal in that the NOPR proposed to require the installation of GIC monitors and magnetometers. The comments raised legitimate concerns about incorporating such a requirement in Reliability Standard TPL-007-1 because of the complexities of siting and operating monitoring devices to achieve the maximum benefits for model validation and situational awareness. In particular, responsible entities may not have the technical capacity to properly install and operate magnetometers, given complicating issues such as man-made interference, calibration, and data interpretation. Accordingly, the Commission determines that requiring responsible entities to collect necessary GIC monitoring and magnetometer data, rather than install GIC monitors and magnetometers, affords greater flexibility while obtaining significant benefits. For example, responsible entities could collaborate with universities and government entities that operate magnetometers to collect necessary magnetometer data, or responsible entities could choose to install GIC monitors or magnetometers to comply with the data collection requirement. While the Commission's primary concern

[120] *Id.* at 8.

is the quality of the data collected, we do not establish a requirement for either approach or promote a particular device for collecting the required data. We also find that cost recovery for prudent costs associated with or incurred to comply with Reliability Standard TPL-007-1 and future revisions to the Reliability Standard, including for the purchase and installation of monitoring devices, will be available to registered entities.[121]

Data Availability

93. We also direct NERC, pursuant to Sections 1500 and 1600 of the NERC Rules of Procedure, to collect and make GIC monitoring and magnetometer data available.[122] We determine that the dissemination of GIC monitoring and magnetometer data will facilitate a greater understanding of GMD events that, over time, will improve Reliability Standard TPL-007-1. The record in this proceeding supports the conclusion that access to GIC monitoring and magnetometer data will help facilitate GMD research, for example, by helping to validate GMD models.[123] To facilitate the prompt dissemination of GIC monitoring and magnetometer data, we address whether GIC monitoring or

[121] NOPR, 151 FERC ¶ 61,134 at P 49 n.60.

[122] If GIC monitoring and magnetometer data is already publicly available (e.g., from a government entity or university), NERC need not duplicate those efforts.

[123] *See*, *e.g.*, March 1, 2016 Technical Conference Tr. 58:22-59:13 (Love); 128:5-129:2 (Overbye); ATC Comments at 6-7("as more measuring devices (including magnetometers and GIC monitors) continue to propagate, the body of field data on magnetic fields and the resultant GICs will continue to increase the understanding of this phenomena and result in better models that more closely match real world conditions … [a]bsent this field data, it is difficult to build accurate models that can be used to plan and operate the transmission system").

magnetometer data should qualify as Confidential Information under the NERC Rules of Procedure.[124]

94. Based on the record in this proceeding, we believe that GIC and magnetometer data typically should not be designated as Confidential Information under the NERC Rules of Procedure. We are not persuaded that the dissemination of GIC monitoring or magnetometer data poses a security risk or that the data otherwise qualify as Confidential Information. CEA and Hydro One have objected, without elaboration, to making data available without the use of non-disclosure agreements.[125] At the March 1, 2016 Technical Conference, panelists were questioned on the topic yet could not identify a security-based or other credible reason for not making such information available to requesters. In comments submitted after the March 1, 2016 Technical Conference, the Trade Associations explained that "GIC measurements, while not as sensitive as transmission planning studies, should also be protected … [because a] potentially malicious actor could conceivably combine GIC information with information from other sources to deduce the configuration and operating conditions of the grid or some portion

[124] Providers of GIC and magnetometer data may request that NERC treat their GIC monitoring and magnetometer data as "Confidential Information," as that term is defined in Section 1500 of the NERC Rules of Procedure. Under the NERC Rules of Procedure, disclosure of Confidential Information by NERC to a requester requires a formal request, notice and opportunity for comment, and an executed non-disclosure agreement for requesters not seeking public disclosure of the information. NERC Rules of Procedure, Section 1503 (Requests for Information) (effective Nov. 4, 2015).

[125] CEA Comments at 15; Hydro One Comments at 2.

of it."[126] The Trade Associations' comments, however, do not substantiate the assertion that the release of GIC monitoring (or magnetometer data) alone poses any risk to the Bulk-Power System. The Trade Associations' comment is also vague by not identifying what "information from other sources" could be combined with GIC monitoring "to deduce the configuration and operating conditions of the grid or some portion of it."

95. In conclusion, given both the lack of substantiated concerns regarding the disclosure of GIC and magnetometer data, and the compelling demonstration that access to these data will support ongoing research and analysis of GMD threats, the Commission expects NERC to make GIC and magnetometer data available. Notwithstanding our findings here, to the extent any entity seeks confidential treatment of the data it provides to NERC, the burden rests on that entity to justify the confidential treatment.[127] Exceptions are possible if the providing entity obtains from NERC, at the time it submits data to NERC, a determination that GIC or magnetometer data qualify as Confidential Information.[128] Entities denied access to GIC and magnetometer data by NERC or

[126] Trade Associations March 7, 2016 Supplemental Comments at 5.

[127] *See* NERC Rules of Procedure, Section 1502.1. To address any substantiated concerns regarding the need for confidentiality of an entity's GIC or magnetometer data, NERC could develop a policy for disseminating such data only after an appropriate time interval (e.g., six months).

[128] We understand that NERC typically does not determine whether information submitted to it under a claim of confidentiality is Confidential Information when receiving such information. *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,060, at PP 195-196 (2007). We expect that, when a submitter seeks a determination

(continued…)

providers denied Confidential Information treatment of GIC and magnetometer data may appeal NERC's decision to the Commission.

E. Corrective Action Plan Deadlines

NERC Petition

96. Reliability Standard TPL-007-1, Requirement R7 provides that:

> Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, that their System does not meet the performance requirements of Table 1 shall develop a Corrective Action Plan addressing how the performance requirements will be met ….

NERC explains that the NERC Glossary defines corrective action plan to mean, "A list of actions and an associated timetable for implementation to remedy a specific problem."[129] Requirement R7.3 states that the corrective action plan shall be provided within "90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need."

NOPR

97. The NOPR proposed to direct NERC to modify Reliability Standard TPL-007-1 to require corrective action plans to be developed within one year of the completion of the

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by NERC of a claim that GIC or magnetometer data qualify as Confidential Information, NERC will decide promptly.

[129] NERC Petition at 31.

GMD Vulnerability Assessment. The NOPR also proposed to direct NERC to modify Reliability Standard TPL-007-1 to require a deadline for non-equipment mitigation measures that is two years following development of the corrective action plan and a deadline for mitigation measures involving equipment installation that is four years following development of the corrective action plan. Recognizing that there is little experience with installing equipment for GMD mitigation, the NOPR stated that the Commission is open to proposals that may differ from its proposal, particularly from any entities with experience in this area. The NOPR also sought comment on appropriate alternative deadlines and whether there should be a mechanism that would allow NERC to consider, on a case-by-case basis, requests for extensions of required deadlines.

Comments

98. NERC states that it does not oppose a one-year deadline for completing the development of corrective action plans.[130] However, NERC contends that imposing deadlines on the completion of mitigation actions would be problematic because of the uncertainties regarding the amount of time needed to install necessary equipment. NERC maintains that deadlines that are too short may cause entities to take mitigation steps that,

[130] NERC contends that a deadline is unnecessary because "NERC expects that applicable entities would determine necessary corrective actions as part of their GMD Vulnerability Assessments for the initial assessment [due 60 months after a final rule in this proceeding goes into effect] as well as subsequent assessments [due every 60 months thereafter]." NERC Comments at 28.

while quicker, would not be as effective as mitigations that take more time to complete. NERC supports allowing extensions if the Commission adopts the NOPR proposal.

99. AEP states that, even if possible, a one-year deadline for developing corrective action plans is too aggressive and would encourage narrow thinking (i.e., registered entities would address GMD mitigation rather than pursue system improvements generally that would also address GMD mitigation). AEP, instead, proposes a two-year deadline. AEP does not support a Commission-imposed deadline for completing mitigation actions, although it supports requiring a time-table in the corrective action plan. AEP notes that the Commission did not impose a specific deadline for completion of corrective actions in Reliability Standard TPL-001-4 (Transmission System Planning Performance). CEA does not support a deadline for the development of corrective action plans because it is already part of the GMD Vulnerability Assessment process. Like AEP, CEA does not support specific deadlines for the completion of mitigation actions and instead supports including time-tables in the corrective action plan. CEA also contends that an extension process would be impracticable.

100. Trade Associations, BPA and Tri-State support the imposition of corrective action plan deadlines as long as entities can request extensions. Gaunt supports the corrective action plan deadlines proposed in the NOPR. Emprimus supports the imposition of deadlines but contends that non-equipment mitigation actions should be completed in 6 months and that there should be a rolling four-year period for equipment mitigation (i.e., after each year, 25 percent of the total mitigation actions should be completed).

Commission Determination

101. The Commission directs NERC to modify Reliability Standard TPL-007-1 to include a deadline of one year from the completion of the GMD Vulnerability Assessments to complete the development of corrective action plans. NERC's statement that it "expects" corrective action plans to be completed at the same time as GMD Vulnerability Assessments concedes the point made in the NOPR that Reliability Standard TPL-007-1 currently lacks a clear deadline for the development of corrective action plans.

102. The Commission also directs NERC to modify Reliability Standard TPL-007-1 to include a two-year deadline after the development of the corrective action plan to complete the implementation of non-hardware mitigation and four-year deadline to complete hardware mitigation. The comments provide contrasting views on the practicality of imposing mitigation deadlines, with NERC and some industry commenters arguing that such deadlines are not warranted while the Trade Associations and other industry commenters support their imposition. Most of these comments, however, support an extension process if the Commission determines that deadlines are necessary. The Commission agrees that NERC should consider extensions of time on a case-by-case basis. The Commission directs NERC to submit these revisions within 18 months of the effective date of this Final Rule.

103. Following adoption of the mitigation deadlines required in this final rule, Reliability Standard TPL-007-1 will establish a recurring five-year schedule for the identification and mitigation of potential GMD risks on the grid, as follows: (1) the

development of corrective action plans must be completed within one year of a GMD Vulnerability Assessment; (2) non-hardware mitigation must be completed within two years following development of corrective action plans; and (3) hardware mitigation must be completed within four years following development of corrective action plans.

104. As discussed elsewhere in this final rule, the Commission recognizes and expects that our collective understanding of the science regarding GMD threats will improve over time as additional research and analysis is conducted. We believe that the recurring five-year cycle will provide, on a going-forward basis, the opportunity to update Reliability Standard TPL-007-1to reflect new or improved scientific understanding of GMD events.

F. Minimization of Load Loss and Curtailment

NERC Petition

105. Reliability Standard TPL-007-1, Requirement R4 states that each responsible entity "shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months." Requirement R4.2 further states that the "study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1."

106. NERC maintains that Table 1 sets forth requirements for system steady state performance. NERC explains that Requirement R4 and Table 1 "address assessments of the effects of GICs on other Bulk-Power System equipment, system operations, and

system stability, including the loss of devices due to GIC impacts."[131] Table 1 provides, in relevant part, that load loss and/or curtailment are permissible elements of the steady state:

> Load loss as a result of manual or automatic Load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

NOPR

107. The NOPR sought comment on the provision in Table 1 that "Load loss or curtailment of Firm Transmission Service should be minimized." The NOPR stated that because the term "minimized" does not represent an objective value, the provision is potentially subject to interpretation and assertions that the term is vague and may not be enforceable. The NOPR also explained that the modifier "should" might indicate that minimization of load loss or curtailment is only an expectation or a guideline rather than a requirement. The NOPR sought comment on how the provision in Table 1 regarding load loss and curtailment will be enforced, including: (1) whether, by using the term "should," Table 1 requires minimization of load loss or curtailment; or both and (2) what constitutes "minimization" and how it will be assessed.

[131] NERC Petition at 39.

Comments

108. NERC states the language in Table 1 is modeled on Reliability Standard TPL-001-4, which provides in part that "an objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm transmission Service following Contingency events." NERC explains that Reliability Standard TPL-007-1 "does not include additional load loss performance criteria used in normal contingency planning because such criteria may not be applicable to GMD Vulnerability Assessment of the impact from a 1-in-100 year GMD event."[132] However, NERC points out that the enforcement of Requirement R4 "would include an evaluation of whether the system meets the Steady State performance requirements of Table 1 which are aimed at protecting against instability, controlled separation, and Cascading."[133] NERC further states that "minimized" in the context of Reliability Standard TPL-007-1 means that "planned Load loss or curtailments are not to exceed amounts necessary to prevent voltage collapse."[134]

109. The Trade Associations agree with the NOPR that the lack of objective criteria could create compliance and enforcement challenges and could limit an operator's actions in real-time. The Trade Associations state that the Commission "should consider

[132] NERC Comments at 29.

[133] *Id.*

[134] *Id.*

whether such language in mandatory requirements invites the unintended consequences of raising reliability risks, especially during real-time emergency conditions … [but] [i]n the interim, the Trade Associations envision that NERC will consider further discussions with stakeholders on the issue prior to TPL-007 implementation."[135]

Commission Determination

110. The Commission accepts the explanation in NERC's comments of what is meant by the term "minimized" in Table 1.

G. Violation Risk Factors and Violation Severity Levels

111. Each requirement of Reliability Standard TPL-007-1 includes one violation risk factor and has an associated set of at least one violation severity level. NERC states that the ranges of penalties for violations will be based on the sanctions table and supporting penalty determination process described in the Commission approved NERC Sanction Guidelines. The NOPR proposed to approve the violation risk factors and violation severity levels submitted by NERC, for the requirements in Reliability Standard TPL-007-1, consistent with the Commission's established guidelines.[136] The Commission did not receive any comments regarding this aspect of the NOPR. Accordingly, the Commission approves the violation risk factors and violation severity levels for the requirements in Reliability Standard TPL-007-1.

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[135] Trade Associations Comments at 28.

[136] *North American Electric Reliability Corp.*, 135 FERC ¶ 61,166 (2011).

H. Implementation Plan and Effective Dates

NERC Petition

112. NERC proposes a phased, five-year implementation period.[137] NERC maintains that the proposed implementation period is necessary: (1) to allow time for entities to develop the required models; (2) for proper sequencing of assessments because thermal impact assessments are dependent on GIC flow calculations that are determined by the responsible planning entity; and (3) to give time for development of viable corrective action plans, which may require applicable entities to "develop, perform, and/or validate new or modified studies, assessments, procedures … [and because] [s]ome mitigation measures may have significant budget, siting, or construction planning requirements."[138]

113. The proposed implementation plan states that Requirement R1 shall become effective on the first day of the first calendar quarter that is six months after Commission approval. For Requirement R2, NERC proposes that the requirement shall become effective on the first day of the first calendar quarter that is 18 months after Commission approval. NERC proposes that Requirement R5 shall become effective on the first day of the first calendar quarter that is 24 months after Commission approval. NERC proposes that Requirement R6 shall become effective on the first day of the first calendar quarter that is 48 months after Commission approval. And for Requirement R3, Requirement

[137] NERC Petition, Ex. B (Implementation Plan for TPL-007-1).

[138] *Id.* at 2.

R4, and Requirement R7, NERC proposes that the requirements shall become effective on the first day of the first calendar quarter that is 60 months after Commission approval.

NOPR

114. The NOPR proposed to approve the implementation plan and effective dates submitted by NERC. However, given the serial nature of the requirements in Reliability Standard TPL-007-1, the Commission expressed concern about the duration of the timeline associated with any mitigation stemming from a corrective action plan and sought comment from NERC and other interested entities as to whether the length of the implementation plan, particularly with respect to Requirements R4, R5, R6, and R7, could be reasonably shortened.

Comments

115. NERC does not support shortening the implementation period. NERC maintains that the proposed implementation period is "appropriate and commensurate with the requirements of the proposed standard" and is based on "industry … projections on the time required for obtaining validated tools, models and data necessary for conducting GMD Vulnerability Assessments through the standard development process."[139] NERC notes that the standard drafting team initially proposed a four-year implementation plan, but received substantial comments expressing concern with only having four years.

[139] NERC Comments at 30.

116. The Trade Associations, BPA, CEA, Joint ISOs/RTOs and Tri-State support the proposed implementation plan for largely the same reasons as NERC.

117. Gaunt proposes a shorter implementation period wherein the initial GMD Vulnerability Assessment would be performed 48 months following the effective date of a final rule in this proceeding, as opposed to the proposed implementation plan's 60 months. Subsequent GMD Vulnerability Assessments would be performed every 48 months thereafter. Briggs states that a "3 or 4 year timeline would likely provide industry with enough time to implement corrective measures and should be considered."[140]

Commission Determination

118. The Commission approves the implementation plan submitted by NERC. When registered entities begin complying with Reliability Standard TPL-007-1, it will likely be the first time that many registered entities will have planned for a GMD event, beyond developing the GMD operational procedures required by Reliability Standard EOP-010-1. Registered entities will gain the capacity to conduct GMD Vulnerability Assessments over the course of the five-year implementation plan by complying with, at phased intervals, the foundational requirements in Reliability Standard TPL-007-1 (i.e., establishing responsibilities for planning and developing models and performance criteria). In addition, as discussed above, NERC's implementation plan affords sufficient

[140] Briggs Comments at 7.

time for NERC to submit and for the Commission to consider the directed revisions to Reliability Standard TPL-007-1 before the completion of the first GMD Vulnerability Assessment. As such, the five-year implementation plan will allow for the incorporation of the revised Reliability Standard in the first round of GMD Vulnerability Assessments.

I. Other Issues

119. Several commenters indicated that the Commission should address the threats posed by EMPs or otherwise raised the issue of EMPs.[141] For example, Briggs states that the Commission should "initiate a process to improve the resilience of the U.S. electric grid to the threat of high altitude electromagnetic pulse (HEMP) attacks, which can be more severe than solar superstorms."[142] However, as the Commission stated in Order No. 779 in directing the development of GMD Reliability Standards and in Order No. 797 in approving the First Stage GMD Reliability Standards, EMPs are not within the scope of the GMD rulemaking proceedings.[143]

120. Holdeman contends that the Commission "should modify the current preemption of States preventing them from having more stringent reliability standards for Commission regulated entities than Commission standards."[144] As the Commission

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[141] *See* Briggs Comments at 7; EIS Comments at 3; JINSA Comments at 2.

[142] Briggs Comments at 7.

[143] Order No. 797, 147 FERC ¶ 61,209 at P 42 (citing Order No. 779, 143 FERC ¶ 61,147 at P 14 n.20).

[144] Holdeman Comments at 2.

indicated in response to similar comments in Order No. 797, section 215(i)(3) of the FPA provides in relevant part that section 215 does not "preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard."[145] Moreover, Reliability Standard TPL-007-1 does not preclude users, owners, and operators of the Bulk-Power System from taking additional steps that are designed to mitigate the effects of GMD events, provided those additional steps are not inconsistent with the Commission-approved Reliability Standards.

121. Certain commenters opposed to Reliability Standard TPL-007-1 contend that its approval could absolve industry of any legal liability should a GMD event cause a disruption to the Bulk-Power System. For example, Resilient Societies "ask[s] the Commission to clarify its expectation that the FERC jurisdictional entities will be held to account, and be subject to liability in the event of gross negligence or willful misconduct in planning for and mitigating solar geomagnetic storms."[146] Resilient Societies also contends that the Commission does not have the legal authority "to grant immunity from liability by setting reliability standards."[147]

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[145] Order No. 797, 147 FERC ¶ 61,209 at P 44 (citing 16 U.S.C. 824o(i)(3)).

[146] Resilient Societies Comments at 62; *see also* CSP Comments at 1 ("It would be far better for FERC to remand Standard TPL-007-1 in its entirety than to approve a reliability standard that would grant liability protection to utilities while blocking the electric grid protection for the public that a 21st century society requires.").

[147] Resilient Societies Comments at 62.

122. The Commission has never stated in the GMD Reliability Standard rulemakings that compliance with Commission-approved Reliability Standards absolves registered entities from legal liability generally, to the extent legal liability exists, should a disruption occur on the Bulk-Power System due to a GMD event. Resilient Societies' comment appears to misconstrue language in Order No. 779 in which the Commission stated, when directing the development of the Second Stage GMD Reliability Standards, that the "Second Stage GMD Reliability Standard should not impose 'strict liability' on responsible entities for failure to ensure the reliability operation of the Bulk-Power System in the face of a GMD event of unforeseen severity."[148] The Commission's statement merely recognized that the Second Stage GMD Reliability Standard should require registered entities to plan against a defined benchmark GMD event, for the purpose of complying with the proposed Reliability Standard, rather than any GMD event generally (i.e., a GMD event that exceeded the severity of the benchmark GMD event). The Commission did not suggest, nor could it suggest, that compliance with a Reliability Standard would absolve registered entities from general legal liability, if any, arising from a disruption to the Bulk-Power System. The only liability the Commission was referring to in Order No. 779 was the potential for penalties or remediation under section 215 of the FPA for failure to comply with a Commission-approved Reliability Standard.

[148] Order No. 779, 143 FERC ¶ 61,147 at P 84.

123. Kappenman, Resilient Societies and Bardin filed comments that addressed the NERC "Level 2" Appeal Panel decision.[149] As a threshold issue, we agree with the Appeal Panel that the issues raised by the appellants in that proceeding are not procedural; instead they address the substantive provisions of Reliability Standard TPL-007-1. Section 8 (Process for Appealing an Action or Inaction) of the NERC Standards Process Manual states:

> Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, retirement or withdrawal of a Reliability Standard, definition, Variance, associated implementation plan, or Interpretation shall have the right to appeal. This appeals process applies only to the NERC Reliability Standards processes as defined in this manual, not to the technical content of the Reliability Standards action.

The appellants, who have the burden of proof under the NERC Rules of Procedure, have not shown that NERC or the standard drafting team failed to comply with any procedural requirements set forth in the NERC Rules of Procedure.[150] Instead, it would appear that the appeal constitutes a collateral attack on the substantive provisions of Reliability Standard TPL-007-1. As the appellants' substantive concerns with Reliability Standard TPL-007-1 have been addressed in this Final Rule, issues surrounding the NERC "Level 2" Appeal Panel decision are, in any case, moot.

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[149] NERC August 17, 2015 Filing at Appendix 1 (Decision of Level 2 Appeal Panel SPM Section 8 Appeal the Foundation For Resilient Societies, Inc. TPL-007-1).

[150] NERC Rules of Procedure, Appendix 3A (Standard Processes Manual), Section 8 (Process for Appealing an Action or Inaction) (effective June 26, 2013).

III. Information Collection Statement

124. The collection of information contained in this final rule is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[151] OMB's regulations require approval of certain informational collection requirements imposed by agency rules.[152]

125. 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.

126. The Commission solicited comments on the need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. The Commission asked that any revised burden or cost estimates submitted by commenters be supported by sufficient detail to understand how the estimates are generated. The Commission received comments on specific requirements in Reliability Standard TPL-007-1, which we address in this Final Rule. However, the Commission did not receive any comments on our reporting burden

[151] 44 U.S.C. 3507(d).

[152] 5 CFR 1320.11.

estimates or on the need for and the purpose of the information collection requirements.[153]

Public Reporting Burden: The Commission approves Reliability Standard TPL-007-1 and the associated implementation plan, violation severity levels, and violation risk factors, as discussed above. Reliability Standard TPL-007-1 will impose new requirements for transmission planners, planning coordinators, transmission owners, and generator owners. Reliability Standard TPL-007-1, Requirement R1 requires planning coordinators, in conjunction with the applicable transmission planner, to identify the responsibilities of the planning coordinator and transmission planner in the planning coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessments. Requirements R2, R3, R4, R5, and R7 refer to the "responsible entity, as determined by Requirement R1," when identifying which applicable planning coordinators or transmission planners are responsible for maintaining models and performing the necessary study or studies. Requirement R2 requires that the responsible entities maintain models for performing the studies needed to complete GMD Vulnerability Assessments, as required in Requirement R4. Requirement R3 requires responsible entities to have criteria for acceptable system steady

[153] While noting the uncertainties surrounding the potential costs associated with implementation of Reliability Standard TPL-007-1 and the potential costs that could arise from a revised Reliability Standard, the Trade Associations stated that they "have no specific comments regarding the OMB cost estimate in the NOPR." Trade Associations Comments at 9.

state voltage performance during a benchmark GMD event. Requirement R4 requires responsible entities to complete a GMD Vulnerability Assessment of the near-term transmission planning horizon once every 60 calendar months. Requirement R5 requires responsible entities to provide GIC flow information to transmission owners and generator owners that own an applicable bulk electric system power transformer in the planning area. This information is necessary for applicable transmission owners and generator owners to conduct the thermal impact assessments required by proposed Requirement R6. Requirement R6 requires applicable transmission owners and generator owners to conduct thermal impact assessments where the maximum effective GIC value provided in proposed Requirement R5, Part 5.1 is 75 A/phase or greater. Requirement R7 requires responsible entities to develop a corrective action plan when its GMD Vulnerability Assessment indicates that its system does not meet the performance requirements of Table 1 – Steady State Planning Events. The corrective action plan must address how the performance requirements will be met, must list the specific deficiencies and associated actions that are necessary to achieve performance, and must set forth a timetable for completion. The Commission estimates the annual reporting burden and cost as follows:

FERC-725N, as modified by the Final Rule in Docket No. RM15-11-000 (TPL-007-1 Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events)[154]						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden Hours & Cost Per Response [155] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
(One-time) Requirement 1	121 (PC & TP)	1	121	Eng. 5 hrs. ($331.75); RK 4 hrs. ($149.80)	1,089 hrs. (605 Eng., 484 RK); $58,267.55 ($40,141.75 Eng., $18,125.80 RK)	$481.55
(On-going) Requirement 1	121 (PC & TP)	1	121	Eng. 3 hrs. ($199.05); RK 2 hrs. ($74.90)	605 hrs. (363 Eng., 242 RK); $33,147.95 ($24,085.05 Eng., $9,062.90 RK)	$273.95

[154] Eng.=engineer; RK =recordkeeping (record clerk); PC=planning coordinator; TP=transmission planner; TO=transmission owner; and GO=generator owner.

[155] The estimates for cost per response are derived using the following formula: Burden Hours per Response * $/hour = Cost per Response. The $66.35/hour figure for an engineer and the $37.45/hour figure for a record clerk are based on data on the average salary plus benefits from the Bureau of Labor Statistics obtainable at http://www.bls.gov/oes/current/naics3_221000.htm and http://www.bls.gov/news.release/ecec.nr0.htm.

(One-time) Requirement 2	121 (PC & TP)	1	121	Eng. 22 hrs. ($1,459.70); RK 18 hrs. ($674.10)	4840 hrs. (2,662 Eng., 2,178 RK); $258,189.80 ($176,623.70 Eng., $81,566.10 RK)	$2,133.80
(On-going) Requirement 2	121 (PC & TP)	1	121	Eng. 5 hrs. ($331.75); RK 3 hrs. ($112.35)	968 hrs. (605 Eng., 363 RK); $53,736.10 ($40,141.75 Eng., $13,594.35 RK)	$444.10
(One-time) Requirement 3	121 (PC & TP)	1	121	Eng. 5 hrs. ($331.75); RK 3 hrs. ($112.35)	968 hrs. (605 Eng., 363 RK); $53,736.10 ($40,141.75 Eng., $13,594.35 RK)	$444.10
(On-going) Requirement 3	121 (PC & TP)	1	121	Eng. 1 hrs. ($66.35); RK 1 hrs. ($37.45)	242 hrs. (121 Eng., 121 RK); $12,559.80 ($8,028.35 Eng., $4,531.45 RK)	$103.80

(On-going) Requirement 4	121 (PC & TP)	1	121	Eng. 27 hrs. ($1,791.45); RK 21 hrs. ($786.45)	5,808 hrs. (3,267 Eng., 2,541 RK); $311,919.85 ($216,765.45 Eng., $95,154.40 RK)	$2,277.85
(On-going) Requirement 5	121 (PC & TP)	1	121	Eng. 9 hrs. ($597.15); RK 7 hrs. ($262.15)	1936 hrs. (1,089 Eng., 847 RK); $103,975.30 ($72,255.15 Eng., $31,720.15 RK)	$859.30
(One-time) Requirement 6	881 (TO & GO)	1	881	Eng. 22 hrs. ($1,459.70); RK 18 hrs. ($674.19)	35,240 hrs. (19,382 Eng., 15,858 RK); $1,879,957.09 ($1,285,995.70 Eng., $593,961.39 RK)	$2,133.89
(On-going) Requirement 6	881 (TO & GO)	1	881	Eng. 2 hrs. ($132.70); RK 2 hrs. ($74.90)	3,524 hrs. (1,762 Eng., 1762 RK); $182,895.60 ($116,908.70 Eng., $65,986.90 RK)	$207.60

(On-going) Requirement 7	121 (PC & TP)	1	121	Eng. 11 hrs. ($729.85); RK 9 hrs. ($337.05)	2,420 hrs. (1,331 Eng., 1,089 RK); $129,094.90 ($88,311.85 Eng., $40,783.05 RK)	$1,066.90
TOTAL			**2851**		**57,640[156] hrs. (31,792 Eng., 25,848 RK); $3,077,480.04 ($2,109,399.20 Eng., $968,080.84 RK)**	

Title: FERC-725N, Mandatory Reliability Standards: TPL Reliability Standards.

Action: Approved Additional Requirements.

OMB Control No: 1902-0264.

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: One time and on-going.

Necessity of the Information: The Commission has reviewed the requirements of Reliability Standard TPL-007-1 and has made a determination that the requirements of

[156] Of the 57,640 total burden hours, 42,137 hours are one-time burden hours, and 15,503 hours are on-going annual burden hours.

this Reliability Standard are necessary to implement section 215 of the FPA. Specifically, these requirements address the threat posed by GMD events to the Bulk-Power System and conform to the Commission's directives regarding development of the Second Stage GMD Reliability Standards, as set forth in Order No. 779.

Internal review: The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

127. 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].

128. Comments concerning the information collections proposed in this notice of proposed rulemaking and the associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please reference FERC-725N and OMB Control No. 1902-0264 in your submission.

IV. Environmental Analysis

129. 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.[157] 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.[158] The actions here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

130. The Regulatory Flexibility Act of 1980 (RFA)[159] generally requires a description and analysis of final rules that will have 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.[160] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the

[157] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

[158] 18 CFR 380.4(a)(2)(ii).

[159] 5 U.S.C. 601-12.

[160] 13 CFR 121.101.

number of employees, including affiliates (from a standard based on megawatt hours).[161] Under SBA's new size standards, planning coordinators, transmission planners, transmission owners, and generator owners are likely included in one of the following categories (with the associated size thresholds noted for each):[162]

- Hydroelectric power generation, at 500 employees
- Fossil fuel electric power generation, at 750 employees
- Nuclear electric power generation, at 750 employees
- Other electric power generation (e.g., solar, wind, geothermal, biomass, and other), at 250 employees
- Electric bulk power transmission and control,[163] at 500 employees

131. Based on these categories, the Commission will use a conservative threshold of 750 employees for all entities.[164] Applying this threshold, the Commission estimates that there are 440 small entities that function as planning coordinators, transmission planners, transmission owners, and/or generator owners. However, the Commission estimates that only a subset of such small entities will be subject to the approved Reliability Standard

[161] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77,343 (Dec. 23, 2013).

[162] 13 CFR 121.201, Sector 22, Utilities.

[163] This category covers transmission planners and planning coordinators.

[164] By using the highest number threshold for all types of entities, our estimate conservatively treats more entities as "small entities."

given the additional applicability criterion in the approved Reliability Standard (i.e., to be subject to the requirements of the approved Reliability Standard, the applicable entity must own or must have a planning area that contains a large power transformer with a high side, wye-grounded winding with terminal voltage greater than 200 kV).

132. Reliability Standard TPL-007- 1 enhances reliability by establishing requirements that require applicable entities to perform GMD Vulnerability Assessments and to mitigate identified vulnerabilities. The Commission estimates that each of the small entities to whom the approved Reliability Standard applies will incur one-time compliance costs of $5,193.34 and annual ongoing costs of $5,233.50.

133. The Commission does not consider the estimated cost per small entity to impose a significant economic impact on a substantial number of small entities. Accordingly, the Commission certifies that the approved Reliability Standard will not have a significant economic impact on a substantial number of small entities.

VI. Document Availability

134. 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, N.E., Room 2A, Washington, DC 20426.

135. 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.

136. 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

137. These regulations are effective **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

APPENDIX

Commenters

Initial Comments

Abbreviation	Commenter
AEP	American Electric Power Service Corporation
APS	Arizona Public Service Company
ATC	American Transmission Company
Baker	Greta Baker
Bardin	David J. Bardin
BPA	Bonneville Power Administration
Briggs	Kevin Briggs
CEA	Canadian Electricity Association
CSP	Center for Security Policy
EIS	Electric Infrastructure Security Council
Emprimus	Emprimus LLC
Exelon	Exelon Corporation
Gaunt	Charles T. Gaunt
Holdeman	Eric Holdeman
Hydro One	Hydro One Networks Inc.
ITC	International Transmission Company
Lloyd's	Lloyd's America, Inc.
JINSA	Jewish Institute for National Security Affairs
Joint ISOs/RTOs	ISO New England Inc., Midcontinent Independent Transmission System Operator, Inc., Independent Electricity System Operator, New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.
Kappenman	John G. Kappenman and Curtis Birnbach
Morris	Eric S. Morris
NERC	North American Electric Reliability Corporation
Resilient Societies	Foundation for Resilient Societies
Roodman	David Roodman
Trade Associations	American Public Power Association, Edison Electric Institute, Electricity Consumers Resource Council, Electric Power Supply Association, Large Public Power Council, National Rural Electric Cooperative Association
Tri-State	Tri-State Generation and Transmission Association, Inc.
USGS	United States Geological Survey

Supplemental Comments

AEP	American Electric Power Service Corporation
Bardin	David J. Bardin
CSP	Center for Security Policy
Gaunt	Charles T. Gaunt
IEEE	IEEE Power and Energy Society Transformers Committee
Kappenman	John G. Kappenman and Curtis Birnbach
NERC	North American Electric Reliability Corporation
Resilient Societies	Foundation for Resilient Societies
Roodman	David Roodman
Trade Associations	American Public Power Association, Edison Electric Institute, Electricity Consumers Resource Council, Electric Power Supply Association, Large Public Power Council, National Rural Electric Cooperative Association
USGS	United States Geological Survey

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156 FERC ¶ 61,207
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RD16-6-000

ORDER APPROVING RELIABILITY STANDARDS

(Issued September 22, 2016)

1. On May 26, 2016, the North American Electric Reliability Corporation (NERC) submitted a petition seeking approval of proposed Reliability Standards IRO-018-1 (Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities) and TOP-010-1 (Real-time Reliability Monitoring and Analysis Capabilities). As discussed in this order, the Commission approves Reliability Standards IRO-018-1 and TOP-010-1 and NERC's proposed implementation plan, violation severity levels and, with the exceptions identified below, violation risk factors.

2. The Commission, as discussed below, directs NERC to submit a compliance filing within 60 days of the date of this order to modify the violation risk factor designations for Requirement R1 of Reliability Standard IRO-018-1 and Requirements R1 and R2 of Reliability Standard TOP-010-1 to "high."

I. Background and NERC Petition

3. The Commission certified NERC as the Electric Reliability Organization, as defined in section 215 of the Federal Power Act (FPA),[1] in July 2006.[2] In Order No. 693, the Commission approved 83 of 107 proposed Reliability Standards submitted by NERC,

[1] 16 U.S.C. § 824o(d) (2012).

[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 ¶ 61,190, *order on reh'g* 119 FERC ¶ 61,046 (2007), *rev. denied sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

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including the original Transmission Operations (TOP) and Interconnection Reliability Operations and Coordination (IRO) Reliability Standards. The Commission also directed NERC to address issues with respect to the TOP and IRO Reliability Standards regarding monitoring and analysis capabilities.

4. NERC contends that the proposed Reliability Standards address: (1) the directives in Order No. 693 requiring operators to have a minimum set of capabilities; (2) recommendations contained in the NERC Operating Committee Real-time Tools Best Practices Task Force Report published in 2008; and (3) a recommendation from the joint Commission-NERC report on the 2011 Arizona-Southern California outage. NERC explains that it developed the proposed Reliability Standards to improve real-time situational awareness capabilities and enhance reliable operations by requiring reliability coordinators, transmission operators, and balancing authorities to provide operators with awareness of monitoring and analysis capabilities, including alarm availability, so that operators may take appropriate steps to protect reliability. NERC states that the 2003 Blackout Report identified inadequate situational awareness as one of the key causes of that blackout, leading to a recommendation (Recommendation 22) for the evaluation of existing and adoption of new and better real-time tools for transmission operators and reliability coordinators. NERC adds that a recommendation (Recommendation 12) from the joint report on the 2011 Arizona-Southern California outage provided that entities "should take measures to ensure their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems."

5. NERC states that, while existing Reliability Standards contain requirements to perform monitoring and real-time assessments, proposed Reliability Standards IRO-018-1 and TOP-010-1 build on these requirements to support effective situational awareness. NERC explains that the proposed Reliability Standards accomplish this by requiring applicable entities to: (1) provide notification to operators of real-time monitoring alarm failures; (2) provide operators with indications of the quality of information being provided by their monitoring and analysis capabilities; and (3) address deficiencies in the quality of information being provided by their monitoring and analysis capabilities.

6. Specifically, NERC states that proposed Reliability Standards IRO-018-1, Requirement R3 and TOP-010-1, Requirement R4 address situational awareness objectives by providing for operator awareness when key alarming tools are not performing as intended. Proposed Reliability Standard IRO-018-1, Requirement R3 requires reliability coordinators to have an alarm process monitor that provides notification to system operators when the failure of a real-time monitoring alarm processor has occurred. Proposed Reliability Standard TOP-010-1, Requirement R4 contains an identical requirement applicable to transmission operators and balancing authorities.

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7. In addition, NERC states that proposed Reliability Standard IRO-018-1, Requirement R1 obligates each reliability coordinator to implement an operating process or procedure to address the quality of the real-time data necessary to perform its real-time monitoring and real-time assessments. Proposed Reliability Standard TOP-010-1, Requirement R1 contains identical requirements applicable to transmission operators; Requirement R2 requires the same of balancing authorities.

8. Further, NERC explains that Reliability Standards IRO-018-1, Requirement R2 and TOP-010-1, Requirement R3 ensure that reliability coordinators and transmission operators, respectively, implement operating processes or procedures to address issues related to the quality of the analysis used in real-time assessments.

9. NERC submits that proposed Reliability Standards IRO-018-1 and TOP-010-1, together with other currently-effective and Commission-approved IRO and TOP Reliability Standards address the relevant reliability concerns underlying the Commission's Order No. 693 directives requiring operators to have a minimum set of capabilities. NERC's implementation plan provides that the proposed Reliability Standards would become effective the first day of the first calendar quarter that is 18 months following Commission approval.

II. Notice of Filing and Responsive Pleading

10. Notice of NERC's Petition was published on June 8, 2016 in the *Federal Register*, 81 Fed. Reg. 36,910 (2016), with comments, protests and motions to intervene due on or before June 22, 2016. Dominion Resources Services, Inc. (Dominion) filed a timely motion to intervene.

III. Discussion

11. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2016), the timely motion to intervene filed by Dominion serves to make it a party to this proceeding.

A. Reliability Standards IRO-018-1 and TOP-010-1

12. Pursuant to section 215(d)(2) of the FPA, the Commission approves Reliability Standards IRO-018-1 and TOP-010-1 as just, reasonable, not unduly discriminatory or preferential and in the public interest. Reliability Standards IRO-018-1 and TOP-010-1 improve real-time situational awareness capabilities and enhance reliable operations by requiring reliability coordinators, transmission operators, and balancing authorities to provide operators with an improved awareness of system conditions analysis capabilities, including alarm availability, so that operators may take appropriate steps to ensure reliability. The Reliability Standards accomplish this by requiring that applicable entities provide notification to operators of real-time system awareness and monitoring alarm

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failures. We agree with NERC that requiring applicable entities to implement operating processes or operating procedures governing the quality of the information they are providing on monitoring and analysis capabilities will enhance reliability. Further, we determine that Reliability Standards IRO-018-1 and TOP-010-1, together with existing Commission-approved Reliability Standards, adequately address the relevant directives in Order No. 693. We also approve NERC's proposed implementation plan, violation severity levels and, with the exceptions discussed below, violation risk factors.

B. Violation Risk Factors

13. On May 18, 2007, the Commission established guidelines for determining whether to approve violation risk factors proposed by NERC.[3] The Commission identified the following five factors for evaluating violation risk factors: (1) consistency with the conclusions of the 2003 Blackout Report; (2) consistency within a Reliability Standard, (3) consistency among Reliability Standards with similar requirements; (4) consistency with NERC's definition of the violation risk factor level; and (5) assignment of violation risk factor levels to those requirements in certain Reliability Standards that co-mingle a higher risk reliability objective and a lower risk reliability objective.[4]

14. NERC contends that it is appropriate, under the Commission's guidelines, to assign "medium" violation risk factors to Requirement R1 of Reliability Standard IRO-018-1 and Requirements R1 and R2 of Reliability Standard TOP-010-1. Regarding the first guideline, NERC maintains that the requirements are not directly connected to the conclusions or critical areas identified in the 2003 Blackout Report but, rather, address specific recommendations from a NERC technical committee.

15. NERC also contends that a "medium" violation risk factor for these requirements satisfies the second and third guidelines because it is consistent within the Reliability Standards and among other Reliability Standards with similar requirements. Specifically, NERC states that a "medium" violation risk factor comports with the second guideline because the Reliability Standards contain similar responsibilities for different applicable entities. NERC also explains that such a designation is consistent with other Reliability Standards that involve effective monitoring and control of the bulk electric system. As examples, NERC points to "medium" violation risk factor designations for Reliability

[3] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, *order on reh'g*, 120 FERC ¶ 61,145 (2007); *North American Electric Reliability Corp.*, 123 FERC ¶ 61,284, at PP 20-35, *order on reh'g & compliance*, 125 FERC ¶ 61,212 (2008); *North American Electric Reliability Corp.*, 135 FERC ¶ 61,166 (2011).

[4] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,145 at P 16.

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Standards TOP-003-3, Requirement R5 and IRO-010-2, Requirement R3, which provide that applicable entities shall provide the data necessary for transmission operators and reliability coordinators to perform real-time monitoring and real-time assessments. In addition, NERC cites Reliability Standard TOP-001- 3, Requirement R9, which requires transmission operators and balancing authorities to notify reliability coordinators and others of planned and unplanned outages of monitoring and assessment capabilities, which has also been assigned a "medium" violation risk factor.

16. NERC contends that the proposed designations are also consistent with NERC's definition of "medium" violation risk factor, and thus consistent with the fourth Commission guideline. NERC explains that the purpose of these Reliability Standards is to address recommendations regarding real-time situational awareness and to require entities to take steps to address data or analysis quality concerns to the extent that it affects their ability to perform real-time monitoring and analysis. NERC believes that violation of any of these requirements could directly affect the ability to effectively monitor and control the bulk electric system, but is unlikely to lead to bulk electric system instability, separation, or cascading failures.

17. With respect to the fifth guideline, NERC states that the proposed violation risk factor assignments do not reflect the lower of multiple reliability objectives as each applicable requirement contains one reliability objective.

18. We determine that the "medium" violation risk factors NERC proposes to assign to Requirement R1 of Reliability Standard IRO-018-1 and Requirements R1 and R2 of Reliability Standard TOP-010-1 are not consistent with the Commission's guidelines. As discussed below, NERC has not adequately justified the proposed "medium" violation risk factor designations. Specifically, we find that the proposed designations are inconsistent with NERC's definition of violation risk factor; the recommendations contained in the 2003 Blackout Report; and other Reliability Standards with similar requirements. Accordingly, we direct NERC to raise these violation risk factor designations to "high."

19. The fourth Commission guideline calls for consistency with NERC's definition of the appropriate violation risk factor level.[5] The Commission-approved NERC definition for "high" violation risk factor states, in pertinent part, that a requirement should be "high" if a violation of the requirement "could place the bulk electric system at an unacceptable risk of instability, separation or cascading failures." In contrast, the Commission-approved NERC definition of "medium" violation risk factor provides that the violation of the underlying requirement "could directly affect the electrical state or

[5] *See North American Electric Reliability Corp.*, 119 FERC ¶ 61,145 at PP 28-31.

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the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System … [but] is unlikely to lead to Bulk Electric System instability, separation, or cascading failures." While NERC states that violation of any of the requirements could directly affect the ability to effectively monitor and control the bulk electric system, NERC contends that violation of these requirements is unlikely to lead to bulk electric system instability, separation, or cascading failures.

20. NERC's assertion that a violation of Requirement R1 of Reliability Standard IRO-018-1 and Requirements R1 and R2 of Reliability Standard TOP-010-1 is unlikely to lead to bulk electric system instability, separation, or cascading failures is unpersuasive. The 2003 Blackout Report identified four groups of causes of the blackout, one of which was failure of the interconnected transmission network's reliability organizations to provide effective real-time diagnostic support.[6] As NERC noted in its petition, Recommendation 22 of the 2003 Blackout Report stated that NERC should "evaluate … the real-time operating tools necessary for reliability [sic] operation and reliability coordination, including backup capabilities…."[7] The 2003 Blackout Report also stated that NERC should require its Operating Committee to "give particular attention in its report to the development of guidance to control areas and reliability coordinators on the use of wide-area situation display systems and the integrity of data used in those systems."[8] Real-time data quality is essential to ensure reliable operation of the interconnected transmission network. Given the importance of effective real-time diagnostic support recognized by NERC's Operating Committee and consistent with the 2003 Blackout Report, we conclude that first and fourth Commission guidelines support raising the violation risk factor designations for Requirement 1 of Reliability Standard IRO-018-1 and Requirements R1 and R2 of Reliability Standard TOP-010-1 to "high."

21. Regarding the third guideline, existing Reliability Standards require real-time monitoring and assessments by reliability coordinators (IRO-002-4 and IRO-008-2), transmission operators (TOP-001-3), and balancing authorities (TOP-001-3). Reliability Standards IRO-002-4, Requirements R3 and R4, IRO-008-2, Requirement R4, and TOP-001-3, Requirement R13 require monitoring and analysis of the bulk electric system and have "high" violation risk factors. The requirements of Reliability Standards IRO-018-1 and TOP-010-1 are designed to ensure the accuracy of the data used in these

[6] U.S.-Canada Power System Outage Task Force, Final Blackout Report (April 2004) at 18, http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf.

[7] *Id.* at 159 (Recommendation 22).

[8] *Id.*

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existing Reliability Standards to perform the required monitoring and analysis activities of the bulk electric system. The quality of the data is an essential element of the monitoring and analysis process.[9] Accordingly, it would be incongruous to designate requirements mandating monitoring and assessments as "high" while designating requirements meant to ensure the accuracy of the data on which those assessments rely with a lower "medium" violation risk factor.

22. We are not persuaded by NERC's reliance on the violation risk factors in existing Reliability Standards TOP-003-3 and IRO-010-2 to support assigning a "medium" violation risk factor to Requirement 1 of Reliability Standard IRO-018-1 and Requirements R1 and R2 of Reliability Standard TOP-010-1. Reliability Standards TOP-003-3 and IRO-010-2 address documentation and specification of data.[10] In contrast, Reliability Standards IRO-018-1, Requirement R1 and TOP-010-1, Requirements R1 and R2 go beyond documentation and specification of data and require the development of an operating process or operating procedure to evaluate "the quality of the Real-time data necessary to perform [] Real-time data monitoring and Real-time Assessments or analysis functions."[11] This distinction justifies assigning a higher violation risk factor to Reliability Standards IRO-018-1, Requirement R1 and TOP-010-1, Requirements R1 and R2.

23. Nor are we persuaded by NERC's citation of a "medium" violation risk factor for Reliability Standard TOP-001-3, Requirement R9. This requirement mandates that each transmission operator and balancing authority notify its reliability coordinator and known impacted interconnected entities of, among other things, all planned outages, and unplanned outages of 30 minutes or more, for monitoring and assessment capabilities, and associated communication channels between the affected entities. This is a

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[9] NERC Petition at 14 ("maintaining adequate situational awareness is essential for the reliable operation of the Bulk Power System … situational awareness means 'ensuring that accurate information on current system conditions … is continuously available…'").

[10] The data specifications in Reliability Standards TOP-003-2, Requirement R5 and IRO-010-2, Requirement R3, cited by NERC, are for "mutually agreeable" formats, processes for resolving conflicts, and security protocols. These mutually agreeable procedural aspects likely would not be developed in Real-time.

[11] NERC Petition at 18. NERC emphasizes the importance of the quality of this type of data by noting that "[e]ntities continue to address lower-priority data quality issues (i.e., data quality issues not affecting Real-time monitoring or analysis) according to their operating practices." *Id.*

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notification requirement, not a real-time performance requirement. The notified entity already is subject to performance requirements relating to its real-time monitoring and assessment capabilities.

IV. Information Collection Statement

24. The Paperwork Reduction Act (PRA) requires each federal agency to seek and obtain Office of Management and Budget (OMB) approval before undertaking a collection of information directed to ten or more persons or contained in a rule of general applicability.[12] OMB regulations require approval of certain information collection requirements imposed by agency rules.[13] Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of an agency rule will not be penalized for failing to respond to the collection of information unless the collection of information displays a valid OMB control number.

25. The Commission will submit the information collection requirements to OMB for its review and approval. The Commission solicits public comments on its need for this information, whether the information will have practical utility, the accuracy of burden and cost estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. Comments are due **[60 days after publication in the FEDERAL REGISTER].**

26. The Commission is approving the proposed Reliability Standards IRO-018-01 (Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities, associated with FERC-725Z (Mandatory Reliability Standards: IRO Reliability Standards)) and TOP-010-1 (Real-time Reliability Monitoring and Analysis Capabilities, associated with FERC-725A (Mandatory Reliability Standards for the Bulk Power System)).

27. The Commission finds that the new TOP and IRO Reliability Standards improve reliability by providing rigorous functional requirements for real-time monitoring and analysis. Reliability Standards IRO-018-1 and TOP-010-1 were created to improve real-time situational awareness capabilities and enhance reliable operations by requiring reliability coordinators, transmission operators, and balancing authorities to provide

[12] 44 U.S.C. § 3507(d) (2012).

[13] 5 C.F.R. § 1320 (2016).

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operators with awareness of monitoring and analysis capabilities, including alarm availability, so that entities may take appropriate steps to ensure reliability.

28. The Commission approves Reliability Standards IRO-018-1 and TOP-010-1, which enhance reliability by accomplishing Blackout Report Recommendation 22 to evaluate and adopt better real-time tools for operators and reliability coordinators and establish requirements to perform real-time monitoring and analysis capabilities to support reliable system operations. The new Reliability Standards build upon existing requirements to support effective real-time monitoring and analysis and improved situational awareness, and thereby enhance reliable operations. Reliability Standard IRO-018-1 is applicable to reliability coordinators. Reliability Standard TOP-010-1 applies to transmission operators and balancing authorities.

Public Reporting Burden: The new TOP and IRO Reliability Standards require applicable entities to provide notification to operators of real-time monitoring of alarm failures. The new standards also require applicable entities to implement operating processes or operating procedures to: (i) provide operators with indication(s) of the quality of information being provided by their monitoring and analysis capabilities; and (ii) address deficiencies in the quality of information being provided by their monitoring and analysis capabilities. Our estimates regarding the number of respondents are based on the NERC Compliance Registry as of April 21, 2016. According to the NERC Compliance Registry, there are 11 reliability coordinators, 100 balancing authorities and 171 transmission operators registered. The additional estimated burden and cost related to the changes in Docket No. RD16-6 are as follows:

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FERC-725Z, changes due to Reliability Standard IRO-018-1							
Entity	**Requirements & Period**	**No. of Respondents[14] (1)**	**Annual No. of Responses per Respondent (2)**	**Total No. of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[15] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
RC[16]	**Year 1 Implementation (reporting)**	11	1	11	60 hrs.; $3,852.00	660 hrs.; $42,372.00	$3,852.00
	Starting in Year 2 (annual reporting)	11	1	11	32 hrs.; $2,054.40	352 hrs.; $22,598.40	$2,054.40
	Annual Record Retention	11	1	11	2 hrs.; $75.38	22 hrs.; $829.18	$75.38
TOTAL BURDEN HRS. PER YEAR						682 hrs. in Year 1; 374 hrs. per year starting in Year 2	

[14] The number of respondents is the estimated number of entities for which there is a change in burden from the current standards to the proposed standards, not the total number of entities from the current or proposed standards that are applicable.

[15] The estimated hourly costs (salary plus benefits) are based on Bureau of Labor Statistics (BLS) information, as of May 2015 (at http://www.bls.gov/oes/current/naics2_22.htm, with updated benefits information for March 2016 at http://www.bls.gov/news.release/ecec.nr0.htm), for an electrical engineer (code 17-2071, $64.20/hour), and for information and record clerks (code 43-4199, $37.69/hour). The hourly figure for engineers is used for reporting; the hourly figure for information and record clerks is used for document retention.

[16] The following Requirements and the associated measures apply to RCs: Requirement R1: A revised data specification and writing the required operating Process/Operating Procedure; Requirement R2: Quality monitoring logs and the data errors and corrective action logs; and Requirement R3: Alarm process monitor performance logs.

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FERC-725A, changes due to TOP-010-1 in Docket No. RD16-6-000							
Entity	**Requirements & Period**	**No. of Respondents[17] (1)**	**Annual No. of Responses per Respondent (2)**	**Total No. of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[18] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
BA[19]	**Year 1 Implementation (reporting)**	100	1	100	70 hrs.; $4,494.00	7,000 hrs.; $449,400.00	$4,494.00
	Starting in Year 2 (annual reporting)	100	1	100	42 hrs.; $2,696.40	4,200 hrs.; $269,640.00	$2,696.40
TOP[20]	**Year 1 implementation (reporting)**	171	1	171	70 hrs.; $4,494.00	11,970 hrs.; $768,474.00	$4,494.00
	Starting in Year 2 (annual reporting)	171	1	171	40 hrs. $2,568.00	6,840 hrs.; $439,128.00	$2,568.00

[17] The number of respondents is the number of entities in which a change in burden from the current standards to the proposed exists, not the total number of entities from the current or proposed standards that are applicable.

[18] The estimated hourly costs (salary plus benefits) are based on Bureau of Labor Statistics (BLS) information, as of May 2015 (at http://www.bls.gov/oes/current/naics2_22.htm, with updated benefits information for March 2016 at http://www.bls.gov/news.release/ecec.nr0.htm), for an electrical engineer (code 17-2071, $64.20/hour), and for information and record clerks record keeper (code 43-4199, $37.69/hour). The hourly figure for engineers is used for reporting; the hourly figure for information and record clerks is used for document retention.

[19] The following Requirements and associated measures apply to balancing authorities: Requirement R1: A revised data specification and writing the required operating process/operating procedure; and Requirement R2: quality monitoring logs and the data errors and corrective action logs.

[20] The following Requirements and associated measures apply to transmission operators: Requirement R1: A revised data specification and writing the required operating process/operating procedure; and Requirement R3: alarm process monitor performance logs to maintain performance logs and corrective action plans.

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BA/TOP	**Annual Record Retention**	271	1	271	2hrs $75.38	542 hrs.; $20,427.98	$75.38
Total Burden Hours Per Year						19,512 hrs. in Year 1; 11,582 hrs. per year, starting in Year 2	

29. The Commission finds that that the new standards clarify and improve upon the currently-effective TOP and IRO Reliability Standards by designating requirements in the new standards that apply to transmission operators and balancing authorities for the TOP standards and reliability coordinators for the IRO standards. Thus, the Commission finds that there are benefits to clarifying and bringing efficiencies to the TOP and IRO Reliability Standards, consistent with the Commission's policy promoting increased efficiencies in Reliability Standards and reducing requirements that are either redundant with other currently-effective requirements or have little reliability benefit.

Title: FERC-725Z (Mandatory Reliability Standards: IRO Reliability Standards) and FERC-725A (Mandatory Reliability Standards for the Bulk-Power System)

Action: Proposed revisions to existing information collections

OMB Control No: 1902-0276 (FERC-725Z); 1902-0244 (FERC-725A)

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

Frequency of Responses: One-time implementation and ongoing.

Necessity of the Information: Reliability Standards IRO-018-1 and TOP-010-1 enhance reliability by adopting better real-time tools for reliability coordinators, transmission operators, and balancing authorities and also establish requirements for real-time monitoring and analysis capabilities to support reliable system operations.

30. 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].

V. Effective Date

31. This order will become effective upon issuance.

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The Commission orders:

(A) Reliability Standards IRO-018-1 and TOP-010-1 are hereby approved, as discussed in the body of this order.

(B) NERC is hereby directed to submit a compliance filing within 60 days of the date of this order designating the violation risk factors for Requirement R1 of Reliability Standard IRO-018-1 and Requirements R1 and R2 of Reliability Standard TOP-010-1 as "high," as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

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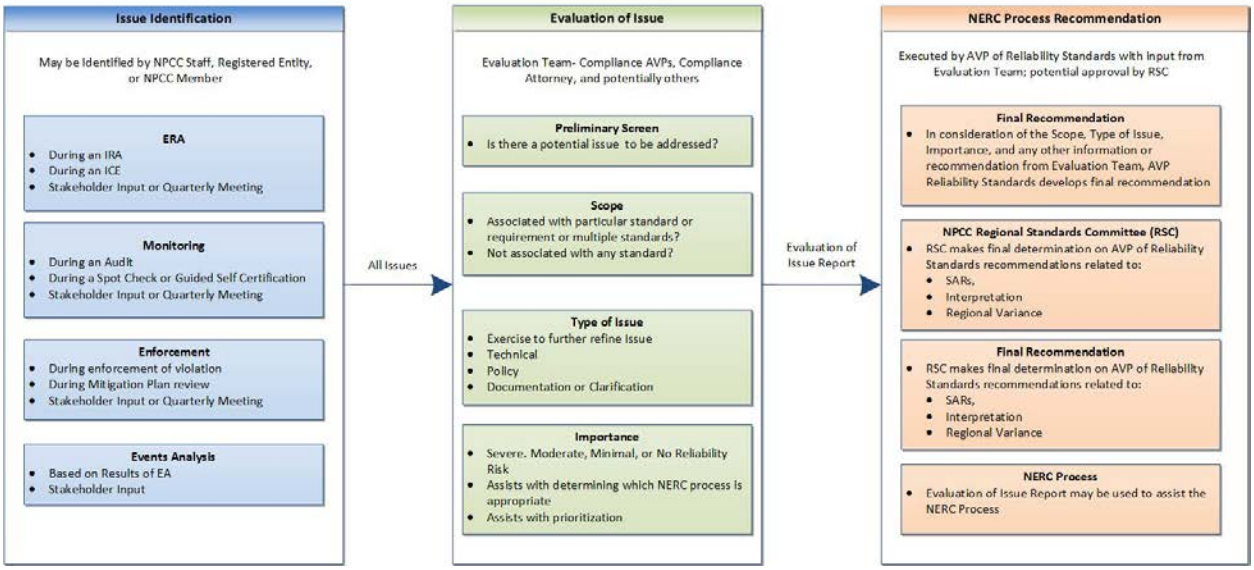
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NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE. OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

1. Overview

1.1. The NPCC Regional Feedback Mechanism process is intended to document how a results-based Reliability Standard improvement Issue ("Issue") is identified, evaluated, and addressed. The process demonstrates how an Issue, which potentially contributes to the improvement of standards and reliability, will be processed within NPCC. This process will effectively and efficiently route Issues to the appropriate NERC Standard Development Process to be addressed. The diagram below illustrates the feedback mechanism process.

NPCC Regional Feedback Mechanism to Improve Reliability Standards



2. Issue Identification

2.1. The areas in which Issues are most likely to be identified are entity risk assessment, Compliance monitoring and enforcement, and Events Analysis.

2.2. In each area, Issues may be identified by NPCC, a registered entity, or an NPCC member.

2.3. Each area shall follow the process described below for identifying Issues.

2.4. Entity Risk Assessment

NPCC's Entity Risk Assessment team ("ERA") is responsible for performing an Inherent Risk Assessments ("IRA") on every registered entity and may perform an Internal Controls Evaluations ("ICE") on registered entities that choose to have their internal controls evaluated.

2.4.1. At any time during or after each IRA or ICE, a person that represents any entity identified in section 2.2 may identify a potential Issue.

2.4.2. The ERA team shall have periodic meetings at least once each calendar quarter to review IRAs and ICEs conducted and to discuss whether the ERA team identifies any potential Issues.

2.5. Monitoring

NPCC audits/monitoring staff is responsible for compliance audits, spot checks, and guided self-certifications.

2.5.1. At any time during or after each audit, spot check, or guided-self certification, a person that represents any entity, identified in section 2.2, may identify a potential Issue.

2.5.2. The audit/monitoring staff shall have periodic meetings at least once each calendar quarter to review monitoring activity conducted and to discuss whether the monitoring team identifies any potential Issues.

2.6. Enforcement

NPCC Enforcement staff is responsible for enforcing non-compliances of reliability standards identified by any means. This includes non-compliance risk assessments and mitigation of non-compliances.

2.6.1. At any time during or after the enforcement of a non-compliance or a group of non-compliances, a person that represents any entity, identified in section 2.2, may identify a potential Issue.

2.6.2. Enforcement staff shall have periodic meetings at least once each calendar quarter to review enforcement activity conducted and to discuss whether enforcement identifies any potential Issues.

2.7. Events Analysis

Events Analysis staff is responsible for reviewing events reported by registered entities.

2.7.1. At any time during or after the evaluation of an event, a member of Events Analysis, or a person from the register entity submitting the events analysis report, may identify a potential Issue.

2.8. To submit an identified Issue, the NPCC Feedback Identification of Issue Form must be completed and submitted by email to feedbackloop@npcc.org.

2.9. Once an Issue is submitted, the Feedback Loop Administrator will review the Issue for completeness and work with the submitter until such time as the Issue has been sufficiently defined.

2.10. Once the issue is sufficiently defined, the Feedback Loop Administrator shall notify the Evaluation Team identified in Section 3.2 and the Compliance Committee of the identified Issue (via email) and place information related to the Issue into the Feedback Loop Tracking Sheet.

3. Evaluation

3.1. Once an Issue is identified, it must be evaluated. This evaluation is not intended to find a solution to the Issue nor is it intended to replicate or replace the existing means to change the Reliability Standards through the NERC Standard Development Process. Instead, this evaluation is intended to identify the scope, type, and importance of the Issue and to use that information to identify the appropriate means within the existing NERC Standard Development Process to further examine the Issue and/or find a solution to the Issue. The evaluation is also intended to provide valuable input to the relevant NERC Standard Development Process.

3.2. Identification of the Evaluation Team

3.2.1. The Evaluation Team will consist of the AVP of Audits and Risk Assessment or his designee, the AVP of Enforcement & Mitigation or his designee, the Compliance Attorney or his designee, and may also include other personnel.

3.2.2. Additional personnel may request to be added to the Evaluation Team and may be added at the discretion of the Evaluation Team. Such personnel may include personnel from a registered entity, an NPCC member, NERC, another Regional Entity, or a governmental agency.

3.2.3. Upon being notified of an Issue, the Evaluation Team shall appoint an Evaluation Team Leader. If no Evaluation Team Leader is appointed, the Compliance Attorney shall be the default Evaluation Team Leader.

3.3. Evaluation Team Preliminary Screen

3.3.1. Once the Evaluation Team is notified of an Issue, it is expected to perform a preliminary screen within two weeks of such notification, or as soon as practical. The preliminary screen is designed to eliminate identified Issues that do not rise to the level of needing consideration by the Evaluation Team. Not all Issues that pass the preliminary screen will receive a Reliability Standard Process Recommendation.

3.3.2. The preliminary screen factors are:

a. Has the identified Issue already been fully addressed in a reliability standard?
b. Has the identified Issue already been fully addressed by other means?
c. Has the identified Issue already been fully addressed in the last year in the NERC Standards development process?
d. Is the identified Issue currently or previously addressed in one or more NERC Standards development processes or in the process of approval or implementation?

Issues may fail the preliminary screen if the answer to any one of the four factors (a through d above) is “YES” or if the Evaluation Team identifies and documents another reason not to evaluate an identified Issue.

3.3.3. The Evaluation Team is not required to perform a complete evaluation for identified Issues that fail the preliminary screen. Instead, the Evaluation Team shall render a determination documenting the reason or reasons why the identified Issue failed the preliminary screen and notify the Feedback Loop Administrator, the AVP of Reliability Standards, the NPCC Compliance Committee, the NPCC Reliability Standards Committee and the requester. The Feedback Loop Administrator shall provide the relevant input related to the preliminary screen determination into the Feedback Loop Tracking Sheet.

Evaluation of Issue

3.4. Once an Issue passes the preliminary screen, the Evaluation Team shall conduct a full evaluation of the potential Issue. A full evaluation of an Issue considers the scope, type, and the importance of the Issue. It may also consider other characteristics.

3.5. Scope of Issue

The Evaluation Team shall make a recommendation on the scope of the Issue. To identify the scope of the Issue, the Evaluation Team shall determine whether the Issue is related to a specific requirement, a specific Reliability Standard, multiple Reliability Standards, or whether the Issue is not related to any particular Reliability Standard.

3.6. Type of Issue

The Evaluation Team shall make a recommendation identifying the type of Issue. Identifying the type of Issue is not a prescriptive evaluation but an exercise to further refine and document the identified Issue. A non-exhaustive list of factors that may be used to identify the type of Issue is included below. However, each of these factors may not be applicable to certain Issues. Furthermore, there may be other factors not included in the list below that can be used to describe the type of Issue.

a. Is the Issue technical in nature?
b. Does the Issue involve a potential policy determination?
c. Is the Issue related to the clarity of an existing Reliability Standard or requirement?
d. Is the Issue related to documentation or measuring the means of complying with a Reliability Standard or requirement?
e. Is the Issue related to a concept not covered by the Reliability Standards?
f. Is the Issue related to duplication of requirements or Reliability Standards?
g. Other factors?

3.7. Importance of Issue

The Evaluation Team shall make a recommendation on the importance of the Issue. The importance of an Issue may help identify which existing NERC Reliability Standard Develop Process is appropriate and how to prioritize resolution of the Issue. The importance of the Issue may be directly related to the reliability risk of not addressing the Issue. Issue importance may be categorized as Severe, Moderate, Minimal or None as follows:

3.7.1. If the reliability risk of not addressing the Issue is Severe, then the Issue likely requires immediate attention.

3.7.2. If the reliability risk of not addressing the Issue is Moderate, then the Issue may require immediate attention or it may be addressed during a future periodic review of a related Reliability Standard or requirement.

3.7.3. If the reliability risk of not addressing the Issue is Minimal, then the Issue does not require immediate attention and could be addressed in the next review of a related standard (assuming a standard is related to the Issue).

3.7.4. If there is no reliability risk (None) to addressing the Issue, then the Issue does not require immediate attention and may be addressed in the next review of a related standard or the Issue may not need to be addressed at all.

3.8. Other input

3.8.1. The Evaluation Team may include other input in the Evaluation of Issue Report.

a. For example, during its evaluation, the Evaluation Team may have developed amendments to a Reliability Standard that would address the Issue. In such a case, the Evaluation Team should include the developed amendments to a Reliability Standard as recommendations to the NERC Standard Development Process.
b. However, since the evaluation is not intended to replicate or replace the existing NERC Standard Development Process, neither proposed Reliability Standard language nor a solution to address the Issue needs to be included in the Evaluation of Issue Report.

3.8.2. During the evaluation, the Evaluation Team may discover that the identified Issue is being addressed or has been addressed in one or more NERC Standards development processes. In such a case, the Evaluation Team may identify this as other input and may make a recommendation not to pursue the Issue and notify the requester.

3.9. Evaluation of Issue Report

3.9.1. The Evaluation Team is expected to complete an Evaluation of Issue Report within 45 days from the day the Evaluation Team was notified of the Issue or as soon as practical.

3.9.2. The Evaluation of Issue Report shall document
c. The members of the Evaluation Team, including the Evaluation Team Leader
d. The scope of the Issue
e. The type of Issue
f. The importance of the Issue
g. Any other input, if applicable

3.9.3. The Evaluation of Issue Report may also make a recommendation(s) regarding which process should be used to develop amendments to a Reliability Standard.

3.9.4. If the Evaluation Team cannot reach consensus on any particular item within the Evaluation of Issue Report, the relevant AVP or his designee shall make the final determination for such item. In such cases, the non-consensus position on any particular item shall be documented within the Evaluation of Issue Report.

3.9.5. Upon completion, the Evaluation Team Leader shall provide the Evaluation of Issues Report via email to the Feedback Loop Administrator, the AVP of Reliability Standards, the NPCC Compliance Committee, the NPCC Reliability Standards Committee, and the person who submitted the Issue.

3.9.6. The Feedback Loop Administrator shall place the relevant information from the Evaluation of Issue Report into the Feedback Loop Tracking Sheet.

3.9.7. If the Evaluation Team cannot complete an Evaluation of Issue Report within 45 days from the day the Evaluation Team was notified of the Issue, the Evaluation Team Leader shall provide a status report to the CC and the Feedback Loop Administrator. The Feedback Loop Administrator shall provide the relevant input related to the status into the Feedback Loop Tracking Sheet.

4. NERC Reliability Standard Development Process

4.1.1. Upon receipt of the Evaluation of Issue Report, the AVP of Reliability Standards or his designee shall consider the information provided and make a recommendation of whether to further pursue the Issue and which NERC process to pursue the Issue.

4.1.2. Potential NERC Processes include, but are not limited to:

a. Requesting a change to a Reliability Standard through a Standard Authorization Request (SAR)
b. Requesting an interpretation to a Reliability Standard requirement through a Request for Interpretation
c. Requesting a Regional Variance to a Reliability Standard requirement
d. Recommending the development of Implementation Guidance or an Auditor's Practice Guide
e. Requesting an Issue be tracked and reviewed during the next periodic review of the relevant Reliability Standard

4.1.3. The Reliability Standard Committee reviews each SAR, Interpretation, and Regional Variance recommendation from the AVP of Reliability Standards and makes the final determination of whether and how to pursue the Issue.

4.1.4. Each Implementation Guidance, Auditor's Practice Guide, periodic review, or other recommendation from the AVP of Reliability Standards shall be a final determination of whether and how to pursue the Issue.

4.1.5. The AVP of Reliability Standards or the Reliability Standards Committee may, but is not required to, request a presentation of the Issue described in the Evaluation of Issue Report from the Evaluation Team Leader.

4.1.6. The AVP of Reliability Standards or his designee is expected to complete and document a final recommendation within 45 days of receiving the Evaluation of Issue Report or on a schedule determined based on the severity of the Issue, which shall document:

a. The determination of whether to submit the Issue into the NERC Standards Development Processes,
b. The determination of which NERC standards process is best suited to pursue the Issue, and
c. The date the determination was made.

4.1.7. The AVP of Reliability Standards or his designee shall provide the final determination via email to the Feedback Loop Administrator, the Evaluation Team, the NPCC Compliance Committee, the NPCC Reliability Standards Committee, and the person who submitted the Issue.

4.1.8. The Evaluation of Issue Report and/or the final determination may be shared freely to assist the NERC process.

4.1.9. For each Issue, the feedback mechanism process is complete when an Issue fails the preliminary screen (Section 3.3) or the activity in the final determination (Section 4.1.2) is implemented.

4.1.10. The development of CMEP Implementation Guidance is not a Reliability Standard activity. However, it is possible that Issues may be best addressed through CMEP Implementation Guidance as described in the NERC Compliance Guidance Policy. In such cases, the AVP of Reliability Standards shall recommend that the NPCC Compliance Committee examine the Issue from the perspective of developing Implementation Guidance.

5. References

5.1.1. NPCC Feedback Identification of Issue Form

5.1.2. NPCC Feedback Loop Tracking Sheet

5.1.3. NPCC Evaluation of Issue Report

5.1.4. NERC Compliance Guidance Policy

5.1.5. NERC Reliability Standards Development Plan

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NPCC Compliance Committee Process for Submitting Implementation Guidance to NERC

1. Overview

1.1. The NPCC Compliance Committee ("CC") is a Regional Entity Stakeholder Committee and is a pre-qualified organization that may vet and submit to NERC examples proposed for Implementation Guidance in accordance with the NERC Compliance Guidance Policy.

1.2. Implementation Guidance is defined in the NERC Compliance Guidance Policy.

1.3. The CC process to develop and vet examples proposed for Implementation Guidance is described in this document

~~1.3.~~1.4. A flowchart providing and overview of the CC process to develop and vet examples proposed for Implementation Guidance is provided in this document.

2. Submitting Draft Implementation Guidance to the CC

2.1. Any Rregistered Eentity or other NPCC committee, working group, task force or subcommittee may request that the CC vet an example proposed for Implementation Guidance.

2.2. To request the CC vet an example proposed for Implementation Guidance, the registered entity, NPCC committee, working group, task force or subcommittee shall develop and submit Draft Implementation Guidance to the Chair and Vice-Chair of the CC.

2.3. Once the Draft Implementation Guidance is submitted, the Chair or the Vice-Chair of the CC shall provide the Draft Implementation Guidance to the Reliability Standards Committee (RSC) and CC email distribution lists for comment.

2.4. The Chair of the CC shall include the Draft Implementation Guidance as an agenda item during the next CC meeting.

3. CC Development of Implementation Guidance

3.1. The CC may develop Draft Implementation Guidance based on a recommendation from the NPCC Regional Feedback Mechanism process.

3.2. To develop Draft Implementation Guidance, the CC shall select an Implementation Guidance Development Team that will consist of at least 3 persons. At least one person on the Implementation Guidance Development Team shall be an NPCC Staff member. The CC shall also select an Implementation Guidance Development Team Leader. All members of the Implementation Guidance Development Team must be CC Members, RSC members, NPCC Working Group members, NPCC Staff or members of an NPCC Task Force.

3.3. The CC may elect to request an NPCC Task Force develop Draft Compliance Guidance, in lieu of an Implementation Guidance Development Team.

3.4. The Implementation Guidance Development Team or the NPCC Task Force is expected to develop Draft Implementation Guidance or report on its progress in developing the Draft Implementation Guidance within 45 days of being selected.

3.5. The Implementation Guidance Development Team Leader or NPCC Task Force Chair shall provide the Draft Implementation Guidance to the RSC and CC distribution lists via email. The Chair of the CC shall ~~attempt to~~ include the Draft Implementation Guidance as an agenda item during the next CC meeting.

4. Vetting of Implementation Guidance

4.1. All CC Members, RSC Members, and NPCC staff shall have 30 days to provide written comments on the Draft Implementation Guidance. Written comments shall be provided to the CC, the RSC, and the registered entity that submitted the Draft Implementation Guidance (if applicable) via email.

4.2. If there are no written comments during the 30 days or the written comments are supportive and do not include any substantive recommended changes, the CC shall vote on the Draft Implementation Guidance. The vote should normally occur during the next CC meeting.

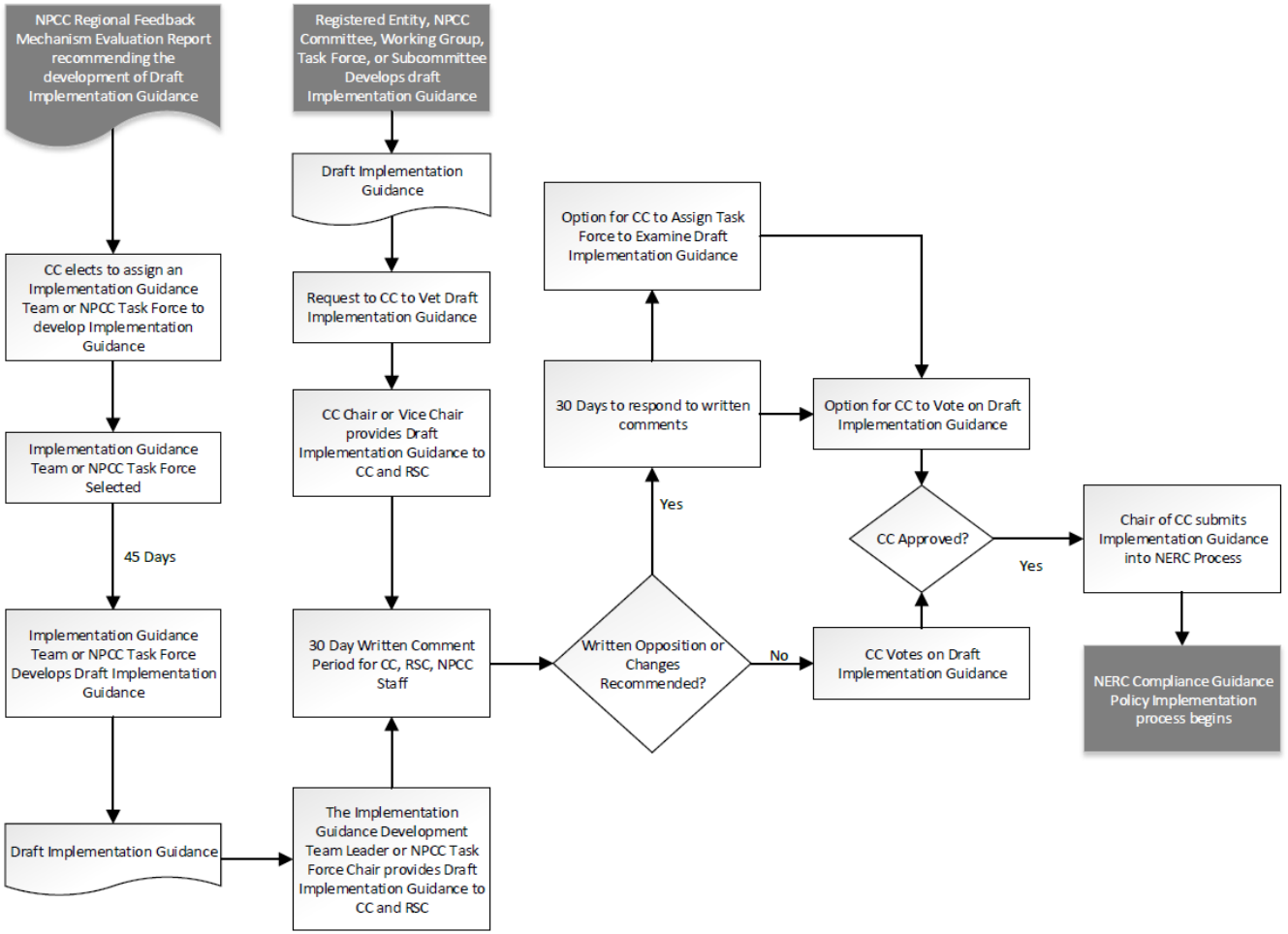
4.3. If there are written comments opposing or recommending substantive changes to the Draft Implementation Guidance, the registered entity, NPCC committee, working group, task force or subcommittee submitting the Draft Implementation Guidance or the Implementation Guidance Development Team should respond to such comments via email to the CC within 30 days.

4.4. After the time has passed for the registered entity or the Implementation Guidance Development Team to respond to the written comments opposing or recommending substantive changes to the Draft Implementation Guidance, the CC may vote on the Draft Implementation Guidance. The CC may also request an NPCC Task Force evaluate the Draft Implementation Guidance.

4.5. If any CC Member company, RSC Member, or NPCC remains opposed to the Draft Implementation Guidance after it has been approved by the CC, such opposition may be documented and provided to the ERO by the party opposed.

4.6. Upon approval by the CC, the Chair of the CC or his designee shall submit the NERC Compliance Guidance Policy Implementation Guidance Submittal Form, the CC approved Implementation Guidance, and any documented opposition to the CC approved Implementation Guidance via email to ComplianceGuidance@nerc.net.

NPCC Compliance Committee Process for Submitting Implementation Guidance to NERC Flowchart Overview



5. References

5.1.1. NERC Compliance Guidance Policy, November 5, 2015

5.1.2. NERC Compliance Guidance Policy Implementation Guidance Submittal Form.

FERC Order 829
Revised Critical Infrastructure Protection Reliability Standards (Supply Chain)

Guy V. Zito
NPCC RSC
October 5-6, 2016

CIP Supply Chain

- **Issued July 21, 2016, (Order is Effective 60 days after publication in Fed. Register)**
  - Develop a new or modified Reliability Standard that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. NERC to submit the new or modified Reliability Standard within one year of the effective date of this Final Rule
  - SC approved solicitation of SDT nominations open through August 18, 2016
  - **NERC to present industry approved standard to BOT August 2017**

CIP Supply Chain

- Each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations. Four attributes (or equally efficient and effective alternatives):
  - **(1) Software Integrity and Authenticity**
  - **(2) Vendor Remote Access**
  - **(3) Information System Planning**
  - **(4) Vendor Risk Management and Procurement Controls**

CIP Supply Chain

- **Software Integrity and authenticity** (listed as a "must" in the Order):
  - the identity of the software publisher for all software and patches that are intended for use on BES Cyber Systems
  - the integrity of the software and patches before they are installed in the BES Cyber System environment

CIP Supply Chain

- **Vendor Remote Access to BES Cyber Systems** (listed as a "must in the Order):
  - address responsible entities logging and controlling all third-party (i.e., vendor) initiated remote access sessions
  - ability to rapidly disable remote access sessions in the event of a system breach
  - Remote access should be operator controlled, time limited, and procedurally similar to "lock out, tag out."

CIP Supply Chain

- **Information System Planning and Procurement** (listed as a "must" in the Order)
  - address how a responsible entity will include security considerations as part of its information system planning and system development lifecycle processes
  - CIP Senior Manager (or Delegate) identification and documentation of the risks of proposed information system planning and system development actions
  - supports, where appropriate, the need for strategic technology refreshes as recommended by ICS-CERT in response to the 2015 Ukraine cybersecurity incident

CIP Supply Chain

- **Vendor Risk Management and Procurement Controls** (listed as a "must" in the Order)
  - address the provision and verification of relevant security concepts in future contracts for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations (5 attributes)
    - vendor security event notification processes
    - vendor personnel termination notification for employees with access to remote and onsite systems
    - product/services vulnerability disclosures, such as accounts that are able to bypass authentication or the presence of hardcoded passwords
    - coordinated incident response activities
    - other related aspects of procurement

- Entities will not be responsible for vendor errors beyond the scope of the controls implemented to comply with the Reliability Standards
- NERC to establish provisions addressing compliance obligations in a manner that avoids shifting liability from a vendor for its mistakes to a responsible entity
- Require a CIP Senior Manager to review and approve the controls adopted to meet the specific security objectives identified in the Reliability Standard at least every 15 months
- CIP Senior Manager should consider any guidance issued by NERC, the U.S. Department of Homeland Security (DHS) or other relevant authorities for the planning, procurement, and operation of industrial control systems and supporting information systems equipment since the prior approval, and identify any changes made to address the recent guidance

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner

or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies

to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, 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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
    a. Loss of a tower line with three or more circuits.[11]
    b. Loss of all Transmission lines on a common Right-of-Way[11].
    c. Loss of a switching station or substation (loss of one voltage level plus transformers).
    d. Loss of all generating units at a generating station.
    e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
    a. Loss of two generating stations resulting from conditions such as:
        i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
        ii. Loss of the use of a large body of water as the cooling source for generation.
        iii. Wildfires.
        iv. Severe weather, e.g., hurricanes, tornadoes, etc.
        v. A successful cyber attack.
        vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
    b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
    a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    e. 3Ø internal breaker fault.
    f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

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 Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in	

		Requirement 1 from Medium to High.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TPL-001-4 — Transmission System Planning Performance Requirements

United States

Standard	Requirement	Enforcement Date	Inactive Date
TPL-001-4	R1.	01/01/2015	
TPL-001-4	1.1.	01/01/2015	
TPL-001-4	1.1.1.	01/01/2015	
TPL-001-4	1.1.2.	01/01/2015	
TPL-001-4	1.1.3.	01/01/2015	
TPL-001-4	1.1.4.	01/01/2015	
TPL-001-4	1.1.5.	01/01/2015	
TPL-001-4	1.1.6.	01/01/2015	
TPL-001-4	R2.	01/01/2016	
TPL-001-4	2.1.	01/01/2016	
TPL-001-4	2.1.1.	01/01/2016	
TPL-001-4	2.1.2.	01/01/2016	
TPL-001-4	2.1.3.	01/01/2016	
TPL-001-4	2.1.4.	01/01/2016	
TPL-001-4	2.1.5.	01/01/2016	
TPL-001-4	2.2.	01/01/2016	
TPL-001-4	2.2.1.	01/01/2016	
TPL-001-4	2.3.	01/01/2016	
TPL-001-4	2.4.	01/01/2016	
TPL-001-4	2.4.1.	01/01/2016	
TPL-001-4	2.4.2.	01/01/2016	
TPL-001-4	2.4.3.	01/01/2016	
TPL-001-4	2.5.	01/01/2016	
TPL-001-4	2.6.	01/01/2016	
TPL-001-4	2.6.1.	01/01/2016	
TPL-001-4	2.6.2.	01/01/2016	
TPL-001-4	2.7.	01/01/2016	
TPL-001-4	2.7.1	01/01/2016	
TPL-001-4	2.7.2.	01/01/2016	

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Enforcement Dates: Standard TPL-001-4 — Transmission System Planning Performance Requirements

United States

TPL-001-4	2.7.3.	01/01/2016	
TPL-001-4	2.7.4.	01/01/2016	
TPL-001-4	2.8	01/01/2016	
TPL-001-4	2.8.1.	01/01/2016	
TPL-001-4	2.8.2.	01/01/2016	
TPL-001-4	R3.	01/01/2016	
TPL-001-4	3.1.	01/01/2016	
TPL-001-4	3.2.	01/01/2016	
TPL-001-4	3.3.	01/01/2016	
TPL-001-4	3.3.1.	01/01/2016	
TPL-001-4	3.3.1.1.	01/01/2016	
TPL-001-4	3.3.1.2.	01/01/2016	
TPL-001-4	3.3.2.	01/01/2016	
TPL-001-4	3.4.	01/01/2016	
TPL-001-4	3.4.1.	01/01/2016	
TPL-001-4	3.5.	01/01/2016	
TPL-001-4	R4.	01/01/2016	
TPL-001-4	4.1.	01/01/2016	
TPL-001-4	4.1.1.	01/01/2016	
TPL-001-4	4.1.2.	01/01/2016	
TPL-001-4	4.1.3.	01/01/2016	
TPL-001-4	4.2.	01/01/2016	
TPL-001-4	4.3.	01/01/2016	
TPL-001-4	4.3.1.	01/01/2016	
TPL-001-4	4.3.1.1.	01/01/2016	
TPL-001-4	4.3.1.2.	01/01/2016	
TPL-001-4	4.3.1.3.	01/01/2016	
TPL-001-4	4.3.2.	01/01/2016	
TPL-001-4	4.4.	01/01/2016	
TPL-001-4	4.4.1.	01/01/2016	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TPL-001-4 — Transmission System Planning Performance Requirements

United States

TPL-001-4	4.5.	01/01/2016	
TPL-001-4	R5.	01/01/2016	
TPL-001-4	R6.	01/01/2016	
TPL-001-4	R7.	01/01/2015	
TPL-001-4	R8.	01/01/2016	
TPL-001-4	8.1.	01/01/2016	

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016
45-day formal comment period with ballot	June 20 - August 3, 2016

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~June 2016~~
45-day formal comment period with additional ballot	September 2016
10-day final ballot	November 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

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

A. Introduction

1. **Title:** **Reliability Coordination – Monitoring and Analysis**
2. **Number:** IRO-002-5
3. **Purpose:** To provide System Operators with the capabilities necessary to monitor and analyze data needed to perform their reliability functions.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

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

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

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

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

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

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

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

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

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

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

R3. Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Reliability Coordinator shall have, and provide upon request, evidence that it tested ~~-~~its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and if the test was unsuccessful, initiated action within two

hours to restore- redundant functionality as specified in Requirement R3. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

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

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

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

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

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

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

- The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and R4 and Measures M1, M2, and M4.
- The Reliability Coordinator shall retain evidence for Requirement R3 and Measure M3 for the most recent 12 calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- The Reliability Coordinator shall keep data or evidence for Requirements R5 and R6 and Measures M5 and M6 for the current calendar year and one previous calendar year.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with one applicable entity, or 5% or less of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with two applicable entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with three applicable entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Reliability Coordinator did not have data exchange capabilities for performing its Operational Planning Analyses with four or more applicable entities or greater than 15% of the applicable entities, whichever is greater.
R2.	N/A	N/A	The Reliability Coordinator had data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments, but did not have redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's ~~Control Center~~primary Control Center, as specified in the requirement.	The Reliability Coordinator did not have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing Real-time monitoring and Real-time Assessments as specified in the requirement.
R3.	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange	The Reliability Coordinator tested its primary Control Center data exchange

	capabilities specified in Requirement R2 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 6 hours and less than or equal to 8 hours.	capabilities specified in Requirement R2 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Reliability Coordinator did not test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality ~~at least once each calendar month~~; OR The Reliability Coordinator tested its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, did not initiate action to restore the redundant functionality in more than 8 hours.
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to provide its System Operator with the authority to approve planned outages and maintenance of its

				telecommunication, monitoring and analysis capabilities.
R5.	N/A	N/A	N/A	The Reliability Coordinator did not monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area.
R6.	N/A	N/A	N/A	The Reliability Coordinator did not have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure.

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised to add missing measures and compliance elements
2	October 17, 2008	Adopted by NERC Board of Trustees	Deleted R2, M3 and associated compliance elements as conforming changes associated with approval of IRO-010-1. Revised as part of IROL Project
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	FERC approval
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	VSLs revised
3	July 25, 2011	Revised under Project 2006-06	Revised
3	August 4, 2011	Approved by Board of Trustees	Retired R1-R8 under Project 2006-06.
4	November 13, 2014	Approved by Board of Trustees	Revisions under Project 2014-03
4	November 19, 2015	FERC approved IRO-002-4. Docket No. RM15-16-000	
5	June 2016	Revised under Project 2016-01	Revised

Guidelines and Technical Basis

None

Rationale

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

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

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

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

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

Rationale for R4 (R6 in IRO-002-5):
The ~~R~~requirement ~~R6~~ was added back from approved IRO-002-2 as the Project 2014-03 SDT found no proposed requirements that covered the issues.

A. Introduction

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

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

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

4. **Applicability**

   4.1. Functional Entities

   ~~4.1.~~4.1.1 Reliability Coordinator

5. **Effective Date:**

   See Implementation Plan~~.~~

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

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

B. Requirements and Measures

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

~~**1.2. Compliance Monitoring and Assessment Processes:**~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~1.2. ~~Data~~ Evidence Retention

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

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

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

The Reliability Coordinator shall retain its current, in force document and any documents in force for the current year and previous calendar year for Requirements R1, R2, and ~~R3~~R4 and Measures M1, M2, and ~~M3~~M4.

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

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

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

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

1.3. Compliance Monitoring and Enforcement Program

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

~~1.4. Additional Compliance Information~~

~~None.~~

Table of Compliance Elements

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

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

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

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

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

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

Version History

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

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

Guidelines and Technical Basis

None

Rationale

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

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

~~**Rationale:**~~

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

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

Rationale for Requirements:

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

Rationale for R2:

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

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

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

Standard Development Timeline

The drafting team maintains this section during development of the standard. It will be removed when the standard becomes effective.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 21, 2016
SAR posted for comment	January 22 - February 22, 2016
45-day formal comment period with ballot	June 20 - August 3, 2016

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~June 2016~~
45-day formal comment period with additional ballot	September 2016
10-day final ballot	November 2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s): None

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

A. Introduction

1. **Title:** **Transmission Operations**

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

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.2. Transmission Operator

   4.1.3. Generator Operator

   4.1.4. Distribution Provider

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- OPA;
- Real-time Assessments (RTA);
- Analysis performed by the TOP as part of BES Exception processing for including a facility in the BES; and

- Analysis which may be specified in the RC's outage coordination process that leads to the identification of a non-BES facility that should be temporarily monitored for determining SOL exceedances.

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

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

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

10.1. Monitor Facilities within its Transmission Operator Area;

10.2. Monitor the status of Remedial Action Schemes within its Transmission Operator Area;

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

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

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

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

M10. Each Transmission Operator shall have, and provide upon request, evidence that could include but is not limited to Energy Management System description documents, computer printouts, Supervisory Control and Data Acquisition (SCADA) data collection, or other equivalent evidence that will be used to confirm that it monitored or obtained and utilized data as required to determine any System Operating Limit (SOL) exceedances within its Transmission Operator Area.

R11. Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority Area

and support Interconnection frequency. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

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

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

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

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

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

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

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

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

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

If such a situation has not occurred, the Transmission Operator may provide an attestation.

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

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

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

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

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

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

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

Redundant and diversely routed data exchange capabilities consist of data exchange infrastructure components (e.g. switches, routers, file servers, power supplies, and network cabling and communication paths between these components in the primary Control Center for the exchange of system operating data) that will provide continued functionality despite failure or malfunction of an individual component within the Transmission Operator's (TOP) ~~Control Center~~primary Control Center. Redundant and diversely routed data exchange capabilities preclude single points of failure in primary Control Center data exchange

infrastructure from halting the flow of Real-time data. Requirement R20 does not require automatic or instantaneous fail-over of data exchange capabilities. Redundancy and diverse routing may be achieved in various ways depending on the arrangement of the infrastructure or hardware within the TOP's ~~Control Center~~primary Control Center.

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

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

R19. Each Transmission Operator shall have data exchange capabilities with the entities it has identified it needs data from in order to perform its Operational Planning Analyses. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

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

R20. Each Transmission Operator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Transmission Operator's primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Balancing Authority, and the entities it has identified it needs data from in order for it to perform its Real-time monitoring and Real-time Assessments. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

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

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

A test for redundant functionality demonstrates that data exchange capabilities will continue to operate despite the malfunction or failure of an individual component. An entity's testing

practices should, over time, examine the various failure modes of its data exchange capabilities. When an actual event successfully exercises the redundant functionality, it can be considered a test for the purposes of the proposed requirement.

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

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

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

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

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

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

R22. Each Balancing Authority shall have data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M22. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities it has identified it needs data from in order to develop its Operating Plan for next-day operations.

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

M23. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, ~~operator logs,~~ system specifications, system diagrams, or other ~~evidence~~ documentation that ~~it has~~lists its data exchange capabilities, ~~with~~ including redundant and diversely routed data exchange infrastructure within the Balancing Authority's ~~Control Center~~primary Control Center, for the exchange of Real-time data with its Reliability Coordinator, Transmission Operator, and the entities it has identified it needs data from in order to perform its Real-time monitoring and analysis functions as specified in the requirement.

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

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

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

M24. Each Balancing Authority shall have, and provide upon request, evidence that it tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, or experienced an event that demonstrated the redundant functionality; and, if the test was unsuccessful, initiated action within two hours to restore redundant functionality as specified in Requirement R24. Evidence could

include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, or electronic communications.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- Each Balancing Authority, Transmission Operator, Generator Operator, and Distribution Provider shall each keep data or evidence for each applicable Requirement R1 through R11, and Measure M1 through M11, for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_V as specified in Requirement R12 and Measure M12.
- Each Transmission Operator shall keep data or evidence for Requirement R13 and Measure M13 for a rolling 30-day period, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- Each Transmission Operator shall retain evidence and that it initiated its Operating Plan to mitigate a SOL exceedance as specified in Requirement R14 and Measurement M14 for three calendar years.

- Each Transmission Operator and Balancing Authority shall each keep data or evidence for each applicable Requirement R15 through R20, and Measure M15 through M20 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Transmission Operator shall keep evidence for Requirement R21 and Measure M21 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall each keep data or evidence for each applicable Requirement R22 through R23, and Measure M22 through M23 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.
- Each Balancing Authority shall keep evidence for Requirement R24 and Measure M24 for the most recent twelve calendar months, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

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

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

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

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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	channels between the affected entities.	channels between the affected entities.		telemetering and control equipment, monitoring and assessment capabilities, or associated communication channels between the affected entities.
R10	The Transmission Operator did not monitor, obtain, or utilize one of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize two of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize three of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10, Part 10.1 through 10.6.	The Transmission Operator did not monitor, obtain, or utilize four or more of the items required or identified as necessary by the Transmission Operator and listed in Requirement R10 Part 10.1 through 10.6.
R11	N/A	N/A	The Balancing Authority did not monitor the status of Remedial Action Schemes that impact generation or Load, in order to maintain generation-Load-interchange balance within its Balancing Authority	The Balancing Authority did not monitor its Balancing Authority Area, in order to maintain generation-Load-interchange balance within its Balancing Authority Area and support Interconnection frequency.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Area and support Interconnection frequency.	
R12	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R13	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for one 30-minute period within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for two 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for three 30-minute periods within that 24-hour period.	For any sample 24-hour period within the 30-day retention period, the Transmission Operator's Real-time Assessment was not conducted for four or more 30-minute periods within that 24-hour period.
R14.	N/A	N/A	N/A	The Transmission Operator did not initiate its Operating Plan for mitigating a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment
R15.	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions taken

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to return the System to within limits when a SOL had been exceeded.
R16.	N/A	N/A	N/A	The Transmission Operator did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R17.	N/A	N/A	N/A	The Balancing Authority did not provide its System Operators with the authority to approve planned outages and maintenance of its telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between affected entities.
R18	N/A	N/A	N/A	The Transmission Operator failed to operate to the most limiting parameter in

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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~Center~~primary Control Center, as specified in the Requirement.	
R21	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once ~~each~~ every 90	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test,	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once ~~each~~ every 90 calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant	The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Transmission Operator did not test its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality ~~at least once each calendar month~~; OR The Transmission Operator tested its primary Control Center data exchange capabilities specified in Requirement R20 for redundant functionality at least once ~~each~~ every 90

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 2 hours and less than or equal to 4 hours.	initiated action to restore the redundant functionality in more than 4 hours and less than or equal to 6 hours.	functionality in more than 6 hours and less than or equal to 8 hours.	calendar ~~month~~ days but, following an unsuccessful test, initiated action to restore the redundant functionality in more than 8 hours.
R22	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with one identified entity, or 5% or less of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with two identified entities, or more than 5% or less than or equal to 10% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with three identified entities, or more than 10% or less than or equal to 15% of the applicable entities, whichever is greater.	The Balancing Authority did not have data exchange capabilities for developing its Operating Plan with four or more identified entities or greater than 15% of the applicable entities, whichever is greater.
R23	N/A	N/A	The Balancing Authority had data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and	The Balancing Authority did not have data exchange capabilities with its Reliability Coordinator, Transmission Operator, and identified entities for performing Real-time monitoring and analysis

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			analysis functions, but did not have redundant and diversely routed data exchange infrastructure within the Balancing Authority's ~~Control Center~~primary Control Center, as specified in the Requirement.	functions as specified in the Requirement.
R24	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 90 calendar days but less than or equal to 120 calendar days since the previous test; OR The Balancing Authority tested its primary Control	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 120 calendar days but less than or equal to 150 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 150 calendar days but less than or equal to 180 calendar days since the previous test; OR The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for	The Balancing Authority tested its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality, but did so more than 180 calendar days since the previous test; OR The Balancing Authority did not test its primary Control Center data exchange capabilities specified in Requirement R23 for redundant functionality ~~at least once each calendar month~~; OR

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

D. Regional Variances

None.

E. Associated Documents

The Implementation Plan and other project documents can be found on the project page.

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

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

Version History

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

Guidelines and Technical Basis

None

Rationale

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

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

Rationale for Requirement R3:

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

Rationale for Requirement R10:

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

Rationale for Requirement R13:

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

Rationale for Requirement R14:

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

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

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

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

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

A. Introduction

1. **Title: Transmission Operations**

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

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

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

5. **Effective Date:**

   See Implementation Plan~~.~~

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

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

B. Requirements and Measures

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

M2~~0~~2. Each Balancing Authority shall have, and provide upon request, evidence that could include, but is not limited to, operator logs, system specifications, system diagrams, or other evidence that it has data exchange capabilities with the entities ~~that~~ it has identified ~~that~~ it needs data from in order to ~~maintain reliability in its Balancing Authority Area~~develop its Operating Plan for next-day operations.

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

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

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

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

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

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

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

~~1.2. Compliance Monitoring and Assessment Processes~~

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be~~

~~used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.3.~~1.2. ~~Data~~ Evidence Retention

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

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.~~

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

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

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

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

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

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

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

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

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

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

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

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

1.3. Compliance Monitoring and Enforcement Program

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

~~1.4. Additional Compliance Information~~

~~None.~~

Table of Compliance Elements

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

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

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

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

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

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

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

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

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

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

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

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

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

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

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

Version History

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

Guidelines and Technical Basis

None

Rationale

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

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

~~**Rationale:**~~

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

Rationale for Requirement R3:

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

Rationale for Requirement R10:

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

Rationale for Requirement R13:

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

Rationale for Requirement R14:

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

Rationale for Requirements R16 and R17:

In response to IERP Report recommendation 3 on authority.

Rationale for Requirement R18:

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

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

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

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Implementation Plan

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

Applicable Standard(s)

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

Requested Retirement(s)

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

Prerequisite Standard(s)

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

- None

Applicable Entities

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

Background

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

General Considerations

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

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

Effective Date

IRO-002-5
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-001-4
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

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

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

Initial Performance of Periodic Requirements

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

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

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Violation Risk Factor and Violation Severity Level Justifications

Project 2016-01 - Modifications to TOP and IRO Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Reliability Standard requirements developed in Project 2016-01. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

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

Project 2016-01 Reliability Standards Requirements

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

VRF Justification

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

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

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

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

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

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

VSL Justification

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

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

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

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

VSL Justifications for IRO-002-5 Requirement R1 and TOP-001-4 Requirements R19 and R22	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	VSLs are comparable to approved IRO-002-4 Requirement R1 and approved TOP-001-3 Requirements R19 and R20.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

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

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

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

VSL Justifications for IRO-002-5 Requirement R2 and TOP-001-4 Requirements R20 and R23	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

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

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

VSL Justifications for IRO-002-5 Requirement R3 and TOP-001-4 Requirements R21 and R24	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirements may be described by elements or quantities to evaluate degrees of compliance. Four VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no current compliance obligation for the proposed requirements.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSLs are not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Nomination Form

Project 2016-03 Cyber Security Supply Chain Management

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Thursday, August 18, 2016.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Potential Standards Authorization Request and standards drafting team (SDT) members for Project 2016-03 Cyber Security Supply Chain Management should have significant management experience or subject matter expertise with the global supply system related to communications and control hardware, software, and services affecting BES operations and BES Cyber Systems. Expertise with developing and implementing controls, including policies, practices, guidelines, and standards designed to mitigate the introduction of cybersecurity risks in the supply chain is needed. In particular, drafting team experience is sought in areas associated with the four security objectives identified in Order No. 829, and potential nominees should highlight their experience in one or more of the objectives as part of their nomination:

(1) software integrity and authenticity;
(2) vendor remote access;
(3) information system planning; and
(4) vendor risk management and procurement controls.

Also, there is a need for a team member(s) with an understanding of the CIP Standards as discussed in Order No. 829 as well as procurement practices for BES Cyber Assets, with a focus on cyber security. In addition, compliance, legal, regulatory, facilitation, and technical writing skills are desired. Previous drafting team experience or other experience with development of standards is beneficial, but not required.

A significant time commitment is expected of SDT members to meet the one-year regulatory deadline established in Order No. 829. SDT activities include participation in technical conferences, stakeholder communications and outreach events, periodic drafting team meetings and conference calls. Approximately two in-person meetings per quarter can be expected (on average three full working days each meeting), as well as periodic conference calls as needed.

Additional information about this project is available on the Project 2016-03 Cyber Security Supply Chain Management page. If you have questions, contact Senior Standards Developer, Mark Olson (via email), or at (404) 446-9760.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested SDT (Bio). Highlight any experience in the four security objectives outlined in FERC Order No. 829 (1. software integrity and authenticity; 2. vendor remote access; 3. information system planning; and 4. vendor risk management and procurement controls):

If you are currently a member of any NERC drafting team, please list each team here:

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

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

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

☐ No prior NERC SAR or standard drafting team.

☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

☐ Texas RE	☐ NPCC	☐ SPP RE
☐ FRCC	☐ RF	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

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

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

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

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Organization:		E-mail:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

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

Note: an Interpretation cannot be used to change a standard.

Interpretation 2010-xx: Request for an Interpretation of [Insert Standard Number], Requirement Rx, for [Insert Name of Company]
Date submitted: March 3, 2015 (amended May 8, 2015)
Contact information for person requesting the interpretation:
Name: Steven Parker
Organization: Energy Sector Security Consortium, Inc (EnergySec)
Telephone: 503.621.8179
Email: steve@energysec.org
Identify the standard that needs clarification:
Standard Number (include version number): CIP-002-5.1 (example: PRC-001-1)
Standard Title: Cyber Security — BES Cyber System Categorization
Identify specifically what requirement needs clarification:
Requirement Number and Text of Requirement: R1 For brevity, only relevant parts of the Requirement and Attachment 1 (incorporated by reference) are quoted here. Requirement 1, subpart 1.2 states, "Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2 …" Attachment 1 is incorporated into the requirement by reference. Attachment 1, Section 2, Criterion 2.1 states, "Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." Clarification needed: With respect to the exclusion clause of Criterion 2.1 limiting applicability, should the evaluation be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems? Stated differently, does the phrase "shared BES Cyber Systems" refer to discrete BES Cyber

Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Discussion

Criterion 2.1 introduces the concept of "shared BES Cyber Systems", but it is not clear what is meant by "shared". Additionally, Criterion 2.1 refers to such shared systems in the plural, making it unclear whether the intent was to apply the Criterion to groups of BES Cyber Systems, or simply to indicate that a single generating plant location could have multiple BES Cyber Systems that meet the Criterion.

Further adding to the uncertainty with this requirement are statements made within a NERC Lessons Learned document, "Impact Rating of Generation Resources", dated September 2, 2014. For example, the Lessons Learned document states:

> "If, for instance, the generation units and BES Cyber Systems are connected in a manner that could result in the loss of 1500 MW or more if **one or more** BES Cyber Systems at the plant were compromised or misused, then those shared BES Cyber Systems at the plant (i.e., those that can, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW) must be categorized as medium impact BES Cyber systems." (emphasis added)

In particular, the use of the phrase "one or more" suggests that a collective evaluation is required.

The aforementioned Lessons Learned document also states:

> "If a Responsible Entity adopts the segmentation approach, consistent with criterion 2.1, entities must provide evidence that BES Cyber Systems associated with any group of generating units at generating plants greater than 1500 MW are segmented effectively such that there are no **common mode vulnerabilities** that could result in the loss of 1500 MW or more of generation at a single plant." (emphasis added)

The reference to "common mode vulnerabilities" suggests that BES Cyber Systems should be evaluated as a group in some circumstances, but is unclear as "common mode vulnerabilities" is not a defined term.

The Lessons Learned document also states:

> "For example, Responsible Entities should consider physical locations that could present a single point of failure (e.g., common control rooms for multiple generating units) to determine what physical protections are appropriate."

Again, this language suggests that BES Cyber Systems may need to be evaluated in groups, for example, when multiple BES Cyber Systems are physically co-located.

The Lessons Learned document also contains a flow chart outlining a suggested process for evaluating BES Cyber Systems for impact ratings. That flow chart does not contain a process for grouping BES Cyber Systems for a collective evaluation, therefore suggesting that the impact assessment occurs individually for each discrete BES Cyber System.

A final Lessons Learned document was posted on January 29, 2015. Some of the language referred to above was removed in the final version, but the questions still remain. The final Lessons Learned document maintains the reference to the Guidelines section of the standard that refers to "BES Cyber Systems with common mode vulnerabilities". This

suggests that common mode vulnerabilities are evaluated in the context of groups of BES Cyber Systems.

In addition, the final Lessons Learned provides only two options, protecting all BES Cyber Systems at the medium level, or segmenting the units. The suggested evidence includes references to network segmentation and firewall rules. This suggests that for collections of BES Cyber Systems on a common network, the collective impact would be evaluated rather than their individual impact. Network isolation would be required to avoid this collective analysis.

On the other hand, FAQ 49, released for comment on April 1, 2015, states that a shared BES Cyber System is one that "affects two or more BES Facilities, such as multiple generation units." Likewise, FAQ 50 refers to common mode vulnerabilities as "Any systems that can affect two or more BES Facilities, such as multiple generation units. … Protection systems, fuel-handling systems, cooling water, and air systems are also examples that should be evaluated as common mode vulnerabilities." These responses support an assertion that BES Cyber Systems need only be evaluated individually.

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.

The evaluation of BES Cyber Systems and assignment of impact ratings is a foundational requirement in version 5 of the CIP standards. A clear understanding of the Criteria, and their proper application is essential to ensure BES Cyber Systems are correctly rated so that the appropriate controls can be applied. Furthermore, in this case, confusion regarding a potential collective assessment, and the criteria and process for such an assessment, can lead not only to under or over rating of systems, but also significant expense in re-engineering plant systems and/or security controls.

A proper understanding of this Criterion is critical to ensure entities can comply with CIP-002-5 R1 without undue risk or expense.

Version History

Version	Date	Owner	Change Tracking
1	April 22, 2011		
1	May 27, 2014	Standards Information Staff	Updated template and email address for submittal.

Appendix 1

Interpretation of CIP-002-5.1, Requirement R1, Attachment 1, Criterion 2.1

Requirement Number and Text of Requirement
CIP-002-5.1, Requirement R1 R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: i. Control Centers and backup Control Centers; ii. Transmission stations and substations; iii. Generation resources; iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements; v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above. 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset; 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required). Attachment 1, Criterion 2.1 2. Medium Impact Rating (M) Each BES Cyber System, not included in Section 1 above, associated with any of the following: 2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?
2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:

> The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

> Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

A. Introduction

1. Title: Cyber Security — BES Cyber System Categorization

2. Number: CIP-002-5.1

3. Purpose: To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. Applicability:

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

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

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

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

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

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

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

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

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Interchange Coordinator or Interchange Authority

4.1.6. Reliability Coordinator

4.1.7. Transmission Operator

4.1.8. Transmission Owner

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

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

4.2.1.1. Each UFLS or UVLS System that:

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

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

4.2.1.2. Each Special Protection System or Remedial Action Scheme where the Special Protection System or Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-5.1:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

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

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

5. Effective Dates:

1. **24 Months Minimum** – CIP-002-5.1 shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required CIP-002-5.1 shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

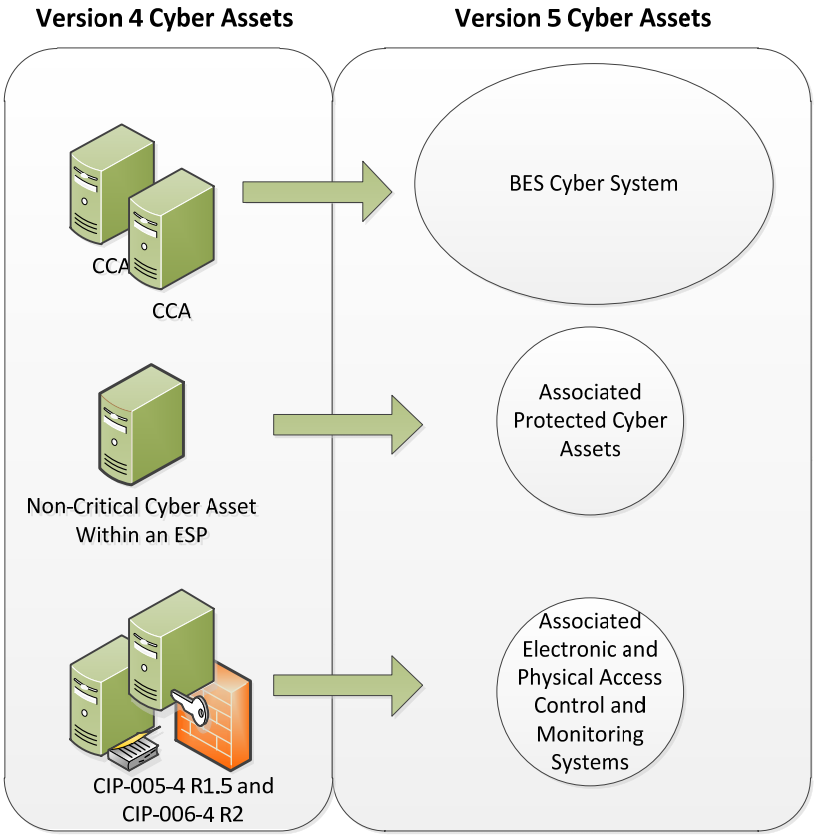
This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

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

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.



In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the "BES Cyber System" term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term "BES Cyber System" is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and

scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

Electronic Access Control or Monitoring Systems ("EACMS") – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.

Physical Access Control Systems ("PACS")– Examples include: authentication servers, card systems, and badge control systems.

Protected Cyber Assets ("PCA") – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

i. Control Centers and backup Control Centers;
ii. Transmission stations and substations;
iii. Generation resources;
iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and
vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber	Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower	Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized at a lower	Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.	category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	**Operations Planning**	**Lower**	The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1) OR The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

CIP-002-5.1 - Attachment 1

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.

1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

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

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

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

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

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

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each Special Protection System (SPS), Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. Special Protection Systems that support the reliable operation of the Bulk Electric System.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-5.1

CIP-002-5.1 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber

Systems that would be subject to CIP-002-5.1. The concept includes a number of named BES reliability operating services. These named services include:

Dynamic Response to BES conditions
Balancing Load and Generation
Controlling Frequency (Real Power)
Controlling Voltage (Reactive Power)
Managing Constraints
Monitoring & Control
Restoration of BES
Situational Awareness
Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
  - Providing actual reserve generation when called upon (GO,GOP)
  - Monitoring that reserves are sufficient (BA)
- Governor Response
  - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
  - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
  - Zone protection for breaker failure (DP, TO, TOP)
  - Breaker protection (DP, TO, TOP)
  - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- Special Protection Systems or Remedial Action Schemes
  - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
  - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
  - Software used to perform calculation (BA)
- Demand Response
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP, DP)

- Non-spinning reserve (contingency reserve)
  - Know generation status, capability, ramp rate, start time (GO, BA)
  - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
  - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
  - Software to calculate unit adjustments (BA)
  - Transmit adjustments to individual units (GOP)
  - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
  - Frequency source, schedule (BA)
  - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
  - Sensors, stator control system, feedback (GO)
- Capacitive resources
  - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
  - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
  - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
  - SCADA (TOP, GOP)
  - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
  - Through black start units (TOP, GOP)
  - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA,TOP,GOP,RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

- When the drafting team uses the term "Facilities", there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms 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.)." In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.
- In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.
- It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating (H)

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some

of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating (M)

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose 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." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

  In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

  By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

  If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

  The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

  IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.

- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.

- Criterion 2.13 categorizes as medium impact those BA Control Centers that "control" 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

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

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.

- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the

backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:

    - Excluded radial facilities that would only provide support for single generation facilities.

    - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

  The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

  Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:

    - 230 kV –> 700 MVA

    - 345 kV –> 1,300 MVA

    - 500 kV –> 2,000 MVA

    - 765 kV –> 3,000 MVA

  In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

    - For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities

would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.

- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.

- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as

specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.

- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.

- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.

- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

  This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric

System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource ("LaaR") Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.

- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that "control" 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

  In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

  The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to

restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

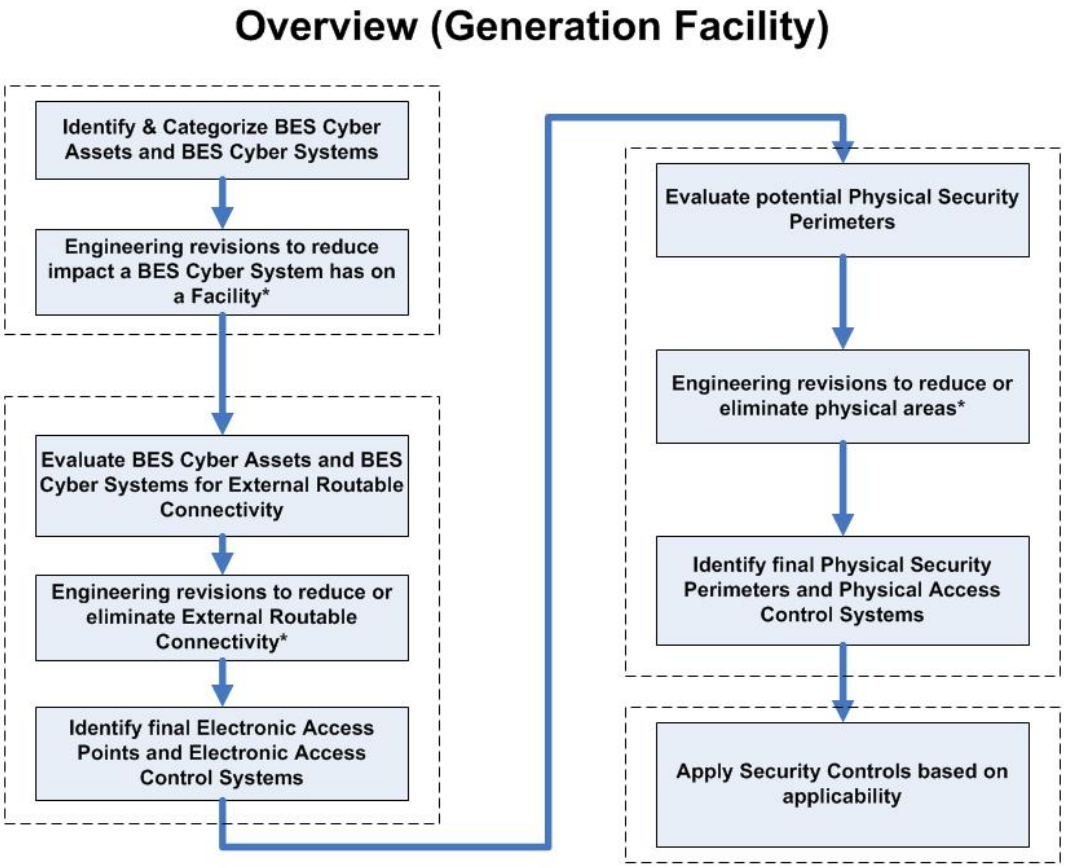
Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

  Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.



* - Engineering revisions will need to be reviewed for cost justification, operational\safety requirements, support requirements, and technical limitations.

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:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of "bright-line" criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager's approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3.	Update

		Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1. (Order becomes effective on 2/3/14.)	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard CIP-002-5.1 — Cyber Security — BES Cyber System Categorization

United States

Standard	Requirement	Enforcement Date	Inactive Date
CIP-002-5.1	All	07/01/2016	

Printed On: September 21, 2016, 05:14 PM

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Proposed Revised Term: "Low Impact External Routable Communication" (LERC)

Revised Term: Low Impact External Routable Communication (LERC)

Revised Definition:

Routable protocol communication that crosses the boundary of an asset containing one or more low impact BES Cyber System(s), excluding communications between intelligent electronic devices used for time-sensitive protection or control functions between non-Control Center BES assets containing low impact BES Cyber Systems including, but not limited to, IEC 61850 GOOSE or vendor proprietary protocols.

Redline to Currently Approved Definition: "Low Impact External Routable Connectivity" (LERC)

Routable protocol communication that crosses the boundary of an asset containing one or more~~Direct user-initiated interactive access or a direct device-to-device connection to a~~ low impact BES Cyber System(s), excluding ~~from a Cyber Asset outside the asset containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection. Point-to-point~~ communications between intelligent electronic devices ~~that~~ used ~~routable communication protocols~~ for time-sensitive protection or control functions between non-Control Center BES ~~Transmission station or substation~~ assets containing low impact BES Cyber Systems including,~~are excluded from this definition (examples of this communication include~~ but ~~are~~ not limited to, IEC 61850 GOOSE or vendor proprietary protocols~~)~~.

Currently Approved Definition of "Low Impact External Routable Connectivity" (LERC):

Direct user-initiated interactive access or a direct device-to-device connection to a low impact BES Cyber System(s) from a Cyber Asset outside the asset containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection. Point-to-point communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between Transmission station or substation assets containing low impact BES Cyber Systems are excluded from this definition (examples of this communication include, but are not limited to, IEC 61850 GOOSE or vendor proprietary protocols).

Retire Currently Approved Term "Low Impact BES Cyber System Electronic Access Point" (LEAP):

Given the modified definition of LERC and the proposed modifications in Reliability CIP-003-7, there is no longer a need for the NERC Glossary term *Low Impact BES Cyber System Electronic Access Point* (LEAP):

> A Cyber Asset interface that controls Low Impact External Routable Connectivity. The Cyber Asset containing the LEAP may reside at a location external to the asset or assets containing low impact BES Cyber Systems.

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Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-003-7 Security Management Controls and Low Impact External Routable Communication (LERC)

Requested Approvals

- Reliability Standard CIP-003-7 - Cyber Security – Security Management Controls
- Definition of Low Impact External Routable Communication (LERC)

Requested Retirements

- Reliability Standard CIP-003-6 - Cyber Security – Security Management Controls
- Definition Low Impact BES Cyber System Electronic Access Point (LEAP)
- Definition of Low Impact External Routable Connectivity (LERC)

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Interchange Coordinator or Interchange Authority
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Background

On January 21, 2016, the Federal Energy Regulatory Commission (Commission) issued Order No. 822, *Revised Critical Infrastructure Protection Reliability Standards,* approving seven Critical Infrastructure Protection (CIP) Reliability Standards and new or modified definitions. In addition to approving the seven CIP Reliability Standards, the Commission, among other things, directed NERC to modify the definition of LERC. The Commission stated:

> 73. Based on the comments received in response to the NOPR, the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule. We agree with NERC and other commenters that a suitable means to address our concern is to modify the Low Impact External Routable Connectivity

definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6.

In addition to modifying the definition consistent with the Commission's directive, the standard drafting team revised the term "LERC" by replacing the word "connectivity" with the word "communication" such that the proposed term for inclusion in the Glossary of Terms used in NERC Reliability Standards (NERC Glossary) is "Low Impact External Routable Communication."

Given the modified definition of LERC and the proposed modifications in Reliability CIP-003-7, there is no longer a need for the NERC Glossary term Low Impact BES Cyber System Electronic Access Point (LEAP). Consequently, NERC is proposing to retire the term LEAP.

General Considerations

This Implementation Plan does not modify the effective date for CIP-003-6 in the Implementation Plan associated with CIP-003-6 nor any of the phased-in compliance dates included therein.

Effective Date

The effective date for the proposed Reliability Standard and NERC Glossary term is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard CIP-003-7 and the NERC Glossary term *Low Impact External Routable Communication* (LERC) shall become effective on the later of September 1, 2018 or the first day of the first calendar quarter that is nine (9) calendar months after the effective date of the applicable governmental authority's order approving the standard and NERC Glossary term, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-003-7 and the NERC Glossary term *Low Impact External Routable Communication* (LERC) shall become effective on the first day of the first calendar quarter that is nine (9) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Planned or Unplanned Changes

Planned or Unplanned Changes Resulting in a Higher Categorization – This implementation Plan incorporates by reference the section in the Implementation Plan associated with CIP-003-5 titled Planned or Unplanned Changes Resulting in a Higher Categorization.[1]

Unplanned Changes Resulting in Low Impact Categorization – This implementation Plan incorporates by reference the section in the Implementation Plan associated with CIP-003-6 titled Unplanned Changes Resulting in Low Impact Categorization. That section provides:

[1] Due to the length of that section, it is not reproduced herein.

For unplanned changes resulting in a low impact categorization where previously the asset containing BES Cyber Systems had no categorization, the Responsible Entity shall comply with all Requirements applicable to low impact BES Cyber Systems within 12 calendar months following the identification and categorization of the affected BES Cyber System.

Retirement Date

Reliability Standard CIP-003-6

Reliability Standard CIP-003-6 shall be retired immediately prior to the effective date of Reliability Standard CIP-003-7 in the particular jurisdiction in which the revised standard is becoming effective.

Current NERC Glossary of Terms of LERC and LEAP

The current definition of LERC and the term LEAP shall be retired from the NERC Glossary of Terms immediately prior to the effective date of the revised LERC term in the particular jurisdiction in which the definition is becoming effective.

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Consideration of Issues and Directives

Project 2016-02 Modifications to CIP Standards

Project 2016-02 Modifications to CIP Standards		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Based on the comments received in response to the NOPR, the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule. We agree with NERC and other commenters that a suitable means to address our concern is to modify the Low Impact External Routable Connectivity definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6.	FERC Order 822, Paragraph 73; issued January 21, 2016	The Project 2016-02 Standard Drafting Team (SDT) revised the definition of the term Low Impact External Routable Connectivity to resolve the ambiguity surrounding the term "direct" identified by the Commission. In doing so, the SDT changed the term to Low Impact External Routable *Communication* (LERC) and simplified the definition so that LERC is an attribute of an asset containing low impact BES Cyber Systems. As revised, LERC exists where there is routable protocol communication that crosses the asset boundary without regard to whether 'direct' or 'indirect' access may occur. The revised LERC definition removes the dependency between the electronic access controls that may be in place and having those controls determine whether LERC exists or not. The SDT determined that indirect access, regardless of what kind of 'security break' is in place causing it to be indirect, is another form of electronic access control that is intended to meet the same security objective. The SDT determined that the requirements should address the electronic access controls rather than having some controls implied through the definition. Therefore, for those assets containing low impact BES Cyber Systems that have

Project 2016-02 Modifications to CIP Standards		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		LERC, the SDT changed the language in Attachment 1, Section 3.1 from requiring a Low Impact Electronic Access Point (LEAP) to requiring that electronic access controls be implemented to meet the security objective of permitting "only necessary electronic access to low impact BES Cyber Systems." Additionally, the SDT expanded the Guidelines and Technical Basis with numerous examples of electronic access control concepts that accomplish this objective. Given the modified definition of LERC and the proposed modifications in Reliability CIP-003-7, there is no longer a need for the NERC Glossary term Low Impact BES Cyber System Electronic Access Point (LEAP). Consequently, the SDT proposed the term's retirement.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 – Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2016-02, Modifications to CIP Standards. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard

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

Guideline (3) – Consistency among Reliability Standards

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

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

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

VRF Justifications for CIP-003-7, Requirement R2	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower was assigned to this requirement. Cyber security plans enable effective implementation of the CIP standard's requirements for low impact BES Cyber Systems. The purpose of plans is for entities to develop an approach involving multiple procedures to address a broad subject matter. Using a plan, Responsible Entities can implement common controls that meet requirements for multiple high, medium, and low impact BES Cyber Systems.
FERC VRF G1 Discussion Guideline 1 - Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2 - Consistency within a Reliability Standard	This requirement calls for the Responsible Entity to implement a documented cyber security plan that contains certain sections specified in Attachment 1. The VRF is only applied at the requirement level and the Requirement Parts are treated in aggregate. While the requirement specifies a number of sections, not necessarily parts, that must be included in the cyber security plan, the VRF is reflective of the plan as a whole. Therefore, the assigned VRF of Lower is consistent with the risk impact of a violation across the entire requirement for BES assets that contain low impact BES Cyber Systems.
FERC VRF G3 Discussion Guideline 3 - Consistency among Reliability Standards	This requirement maps from CIP-003-5, Requirement R1, which has an approved VRF of Medium but applies to Cyber Assets with an inherently lower risk; therefore, the proposed VRF is consistent.
FERC VRF G4 Discussion	Failure to properly implement the cyber security plan would not, under Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state

VRF Justifications for CIP-003-7, Requirement R2	
Proposed VRF	**Lower**
Guideline 4 - Consistency with NERC Definitions of VRFs	or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5 - Treatment of Requirements that Co-mingle More than One Obligation	The cyber security plan requirement encompasses a number of subject matter areas for low impact BES Cyber Systems. The VRF is identified at the risk level represented by all of the plan areas in aggregate. Therefore, the VRF is consistent with the highest risk reliability objective contained in the requirement.

VSLs for CIP-003-7, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems,	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented one or more incident response plans within	The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to Requirement R2, Attachment 1, Section 4. (R2) OR	The Responsible Entity failed to document or implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to Requirement R2, Attachment 1. (R2)

but failed to document one or more Cyber Security Incident response plans according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to Requirement R2, Attachment 1, Section 4. (R2)	its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document physical security controls according to	The Responsible Entity documented the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented electronic access controls for its assets containing low impact BES Cyber Systems, but failed to implement the electronic access controls to low impact BES Cyber Systems according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2)	

	Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2)		

VSL Justifications for CIP-003-7, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously-approved Requirement R2, CIP-003-6. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for CIP-003-7, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSLs are based on a single violation, and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	There is an incremental aspect to a violation of this requirement in that some measurable reliability benefit can be achieved if the Responsible Entity has documented cyber security plan(s) but fails to address one or more of the required sections of Attachment 1. A single failure of this requirement does not compromise network computer security.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	The action of the requirement is to implement documented cyber security plan(s). Documentation of the plan(s) is required, but is not the primary objective of the requirement. Documentation is interdependent with the implementation of the plan in this case; as such, the VSL measures distance from compliance in terms of whether or not the Responsible Entity implemented all the required elements of the plan. The drafting team's intent is that this covers both documentation and implementation and, therefore, accounts for the interdependence of these tasks.

Standard Development Timeline

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

Description of Current Draft

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

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

Previously, the Guidelines and Technical Basis had approximately 10 pages of explanation and numerous reference models to describe different forms of direct vs. indirect access that could be used to determine whether Low Impact External Routable Connectivity existed and thus whether a Low Impact BES Cyber System Electronic Access Point (LEAP) was required.

In this revision, the term *Low Impact External Routable Connectivity* has been changed to *Low Impact External Routable Communication (LERC*) and simplified so that it is an attribute of a BES asset concerning whether there is routable protocol communications across the asset boundary without regard to 'direct vs. indirect' access that may occur. This greatly simplifies and clarifies the definition of LERC. It removes the dependency between the electronic access controls that may be in place and having those controls determine whether LERC exists or not. For those BES assets that have LERC, the SDT changed the requirement from requiring a LEAP to requiring electronic access controls to "permit only necessary electronic access to low impact BES Cyber Systems" (revised Attachment 1, Section 3.1) within the BES asset and expanded the Guidelines and Technical Basis with numerous examples of electronic access controls.

Given the modified definition of LERC and the proposed modifications in Reliability CIP-003-7, there is no longer a need for the NERC Glossary term Low Impact BES Cyber System Electronic Access Point (LEAP). Consequently, NERC is proposing that term for retirement.

In summary, the CIP Standard Drafting Team revised CIP-003-7, Attachments 1 and 2, Sections 2 and 3 and the associated High VSL for Requirement R2. Non-substantive errata changes were also made within the standard, including changing "ES-ISAC" to "E-ISAC".

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

Anticipated Actions	Date
10-day final ballot	October, 2016
NERC Board of Trustees (BOT) adoption	November, 2016

A. Introduction

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

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

3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

   4.1.1 Balancing Authority

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

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

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

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

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

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

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

   4.1.3 Generator Operator

   4.1.4 Generator Owner

4.1.5 Interchange Coordinator or Interchange Authority

4.1.6 Reliability Coordinator

4.1.7 Transmission Operator

4.1.8 Transmission Owner

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

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

4.2.1.1 Each UFLS or UVLS System that:

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

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

4.2.1.2 Each SPS or RAS where the SPS or RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-003-~~6:~~ 7:

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

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

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

5. Effective Dates:

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

6. Background:

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

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

The term documented processes refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in its documented processes, but it must address the applicable requirements.

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

Similarly, the term program may refer to the organization's overall implementation of its policies, plans, and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Reliability Standards could also be referred to as a program. However, the terms program and plan do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high, medium, and low impact BES Cyber Systems. For example, a single

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

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

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

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

B. Requirements and Measures

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

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

1.1.1. Personnel and training (CIP-004);

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

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

1.1.4. System security management (CIP-007);

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

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

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

1.1.8. Information protection (CIP-011); and

1.1.9. Declaring and responding to CIP Exceptional Circumstances.

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

1.2.1. Cyber security awareness;

1.2.2. Physical security controls;

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

1.2.4. Cyber Security Incident response

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

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

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

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

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

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

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

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

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information:

None

2. Table of Compliance Elements

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

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

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

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

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			approval in less than or equal to 16 calendar months of the previous approval. (R1.2)	did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.2)		
R2	**Operations Planning**	**Lower**	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented one or more incident response plans	The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented the determination of	The Responsible Entity failed to document or implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to ~~CIP-003-6,~~ Requirement R2, Attachment 1. (R2~~)~~).

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, but failed to document one or more Cyber Security Incident response plans according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plans within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to ~~CIP-003-6,~~ Requirement R2,	within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. ~~(R2)~~ (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of	whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity ~~Sector~~ Information Sharing and Analysis Center (~~ES~~E-ISAC) according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented ~~and implemented electronic access controls for LERC, but failed to implement a LEAP or permit inbound and outbound access according to CIP-003-6, Requirement R2, Attachment 1, Section 3. (R2)~~ ~~OR~~	

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

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 3. (R2)	security controls according to ~~CIP-003-6,~~ Requirement R2, Attachment 1, Section 2. (R2)	
R3	**Operations Planning**	**Medium**	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR

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

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-~~6~~7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						specific actions delegated, but did not document changes to the delegate within 60 calendar days of the change. (R4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-003-5.	
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct

Version	Date	Action	Change Tracking
			language and communication networks.
6	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC Order issued approving CIP-003-6. Docket No. RM15-14-000	
7	TBD	Adopted by the NERC Board of Trustees.	Revised to address FERC Order 822 directive regarding definition of LERC

~~CIP-003-6 –~~ Attachment 1

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

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

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

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

Section 2. Physical Security Controls: Each Responsible Entity shall control physical access, based on need as determined by the Responsible Entity, to (1) the asset or the locations of the low impact BES Cyber Systems within the asset ~~and (2) the Low Impact BES Cyber System Electronic Access Points (LEAPs),~~, and (2) the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.

Section 3. Electronic Access Controls: Each Responsible Entity shall:

3.1 ~~For~~Implement electronic access control(s) for LERC, if any, ~~implement a LEAP~~ to permit only necessary ~~inbound and outbound bi-directional routable protocol access; and~~electronic access to low impact BES Cyber System(s).

3.2 Implement authentication for all Dial-up Connectivity, if any, that provides access to low impact BES Cyber Systems, per Cyber Asset capability.

Section 4. Cyber Security Incident Response: Each Responsible Entity shall have one or more Cyber Security Incident response plan(s), either by asset or group of assets, which shall include:

4.1 Identification, classification, and response to Cyber Security Incidents;

4.2 Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity ~~Sector~~ Information Sharing and Analysis Center (~~ES~~E-ISAC), unless prohibited by law;

4.3 Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals;

4.4 Incident handling for Cyber Security Incidents;

4.5 Testing the Cyber Security Incident response plan(s) at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and

4.6 Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.

~~CIP-003-6 –~~ Attachment 2

Examples of Evidence for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Section 1. Cyber Security Awareness: An example of evidence for Section 1 may include, but is not limited to, documentation that the reinforcement of cyber security practices occurred at least once every 15 calendar months. The evidence could be documentation through one or more of the following methods:

- Direct communications (for example, e-mails, memos, or computer-based training);
- Indirect communications (for example, posters, intranet, or brochures); or
- Management support and reinforcement (for example, presentations or meetings).

Section 2. Physical Security Controls: Examples of evidence for Section 2 may include, but are not limited to:

- Documentation of the selected access control(s) (e.g., card key, locks, perimeter controls), monitoring controls (e.g., alarm systems, human observation), or other operational, procedural, or technical physical security controls that control physical access to both:
  a. The asset, if any, or the locations of the low impact BES Cyber Systems within the asset; and
  b. The Cyber Asset specified by the Responsible Entity that provides electronic access controls implemented for Section 3.1, if any~~, containing a LEAP~~.

Section 3. Electronic Access Controls: Examples of evidence for Section 3 may include, but are not limited to:

1. Documentation, such as representative diagrams or lists of implemented electronic access controls (e.g., restricting IP addresses, ports, or services; authenticating users; air-gapping networks; terminating routable protocol sessions on a non-BES Cyber Asset; implementing unidirectional gateways) showing that ~~inbound and outbound connections~~ for ~~any LEAP(s) are~~LERC at each asset or group of assets containing low impact BES Cyber Systems, is confined ~~to~~ only ~~those~~to that access the Responsible Entity deems necessary ~~(e.g., by restricting IP addresses, ports, or services); and documentation~~; and

~~1.~~2. Documentation of authentication for Dial-up Connectivity (e.g., dial out only to a preprogrammed number to deliver data, dial-back modems, modems that must be remotely controlled by the control center or control room, or access control on the BES Cyber System).

Section 4. Cyber Security Incident Response: An example of evidence for Section 4 may include, but is not limited to, dated documentation, such as policies, procedures, or process documents of one or more Cyber Security Incident response plan(s) developed either by asset or group of assets that include the following processes:

1. to identify, classify, and respond to Cyber Security Incidents; to determine whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and for notifying the Electricity ~~Sector~~ Information Sharing and Analysis Center (~~ES~~E-ISAC);
2. to identify and document the roles and responsibilities for Cyber Security Incident response by groups or individuals (e.g., initiating, documenting, monitoring, reporting, etc.);
3. for incident handling of a Cyber Security Incident (e.g., containment, eradication, or recovery/incident resolution);
4. for testing the plan(s) along with the dated documentation that a test has been completed at least once every 36 calendar months; and
5. to update, as needed, Cyber Security Incident response plan(s) within 180 calendar days after completion of a test or actual Reportable Cyber Security Incident.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

In developing policies in compliance with Requirement R1, the number of policies and their content should be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering the required topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-~~6~~7, Requirement R1.

If a Responsible Entity has any high or medium impact BES Cyber Systems, the one or more cyber security policies must cover the nine subject matter areas required by CIP-003-~~6~~7, Requirement R1, Part 1.1. If a Responsible Entity has identified from CIP-002 any *assets containing low impact BES Cyber Systems*~~,~~, also referred to herein as ~~("~~BES assets~~"),~~ the one or more cyber security policies must cover the four subject matter areas required by Requirement R1, Part 1.2.

Responsible Entities that have multiple-impact rated BES Cyber Systems are not required to create separate cyber security policies for high, medium, or low impact BES Cyber Systems. The Responsible Entities have the flexibility to develop policies that cover all three impact ratings.

Implementation of the cyber security policy is not specifically included in CIP-003-~~6~~7, Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-003 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements in

NERC cyber security Reliability Standards, but to develop a holistic cyber security policy appropriate for its organization. Elements of a policy that extend beyond the scope of NERC's cyber security Reliability Standards will not be considered candidates for potential violations although they will help demonstrate the organization's internal culture of compliance and posture towards cyber security.

For Part 1.1, the Responsible Entity should consider the following for each of the required topics in its one or more cyber security policies for medium and high impact BES Cyber Systems, if any:

1.1.1 Personnel and training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

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

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN "split-tunneling" or "dual-homed" workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity's Interactive Remote Access controls

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

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

1.1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts

- Monitoring and logging of BES Cyber Systems

1.1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

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

- Availability of spare components
- Availability of system backups

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

- Initiation of change requests
- Approval of changes
- Break-fix processes

1.1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

1.1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

Requirements relating to exceptions to a Responsible Entity's security policies were removed because it is a general management issue that is not within the scope of a reliability requirement. It is an internal policy requirement and not a reliability requirement. However, Responsible Entities are encouraged to continue this practice as a component of their cyber security policies.

In this and all subsequent required approvals in the NERC CIP Reliability Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

Requirement R2:

Using the list of assets containing low impact BES Cyber Systems from CIP-002, the intent of the requirement is for each Responsible Entity to create, document, and implement one or more cyber security plan(s) that addresses objective criteria for the protection of low impact BES Cyber Systems. The protections required by Requirement R2 reflect the level of risk that misuse or the unavailability of low impact BES Cyber Systems poses to the BES. The intent is that the required protections are part of a program that covers the low impact BES Cyber Systems

collectively either at an asset or site level (assets containing low impact BES Cyber Systems), but not at an individual device or system level.

There are four subject matter areas, as identified in Attachment 1, that must be covered by the cyber security plan: (1) cyber security awareness, (2) physical security controls, (3) electronic access controls for LERC and Dial-up Connectivity, and (4) Cyber Security Incident response.

Requirement R2, Attachment 1

As noted, Attachment 1 contains the sections that must be in the cyber security plan(s). The intent is to allow entities that have a combination of high, medium, and low impact BES Cyber Systems the flexibility to choose, if desired, to cover their low impact BES Cyber Systems (or any subset) under their programs used for the high or medium impact BES Cyber Systems rather than maintain two separate programs. Guidance for each of the four subject matter areas of Attachment 1 is provided below.

Requirement R2, Attachment 1, Section 1 – Cyber Security Awareness

The intent of the cyber security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. The entity has the discretion to determine the topics to be addressed and the manner in which it will communicate these topics. As evidence of compliance, the Responsible Entity should be able to produce the awareness material that was delivered according to the delivery method(s) (e.g., posters, emails, or topics at staff meetings, etc.). The Responsible Entity is not required to maintain lists of recipients and track the reception of the awareness material by personnel.

Although the focus of the awareness is cyber security, it does not mean that only technology-related topics can be included in the program. Appropriate physical security topics (e.g., tailgating awareness and protection of badges for physical security, or “If you see something, say something” campaigns, etc.) are valid for cyber security awareness. The intent is to cover topics concerning any aspect of the protection of BES Cyber Systems.

Requirement R2, Attachment 1, Section 2 – Physical Security Controls

The Responsible Entity must document and implement methods to control physical access to (1) the asset or the locations of low impact BES Cyber Systems ~~at assets containing low impact BES~~ within the asset, and (2) Cyber ~~System~~Assets that implement the electronic access control(s) ~~and (2) LEAPs~~specified by the Responsible Entity in Section 3, if any. If ~~the LEAP is~~these Cyber Assets are located within the BES asset and ~~inherits~~inherit the same controls outlined in Section 2, this can be noted by the Responsible Entity in either its policies or cyber security plan(s) to avoid duplicate documentation of the same controls.

The Responsible Entity has the flexibility in the selection of the methods used to meet the objective to control physical access to the asset(s) containing low impact BES Cyber ~~Systems,~~System(s) or the low impact BES Cyber Systems themselves, ~~or LEAPs~~as well as physical protection of the electronic access control Cyber Assets specified by the Responsible Entity, if any. The Responsible Entity may use one or a combination of access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may use perimeter controls (e.g., fences with locked gates, guards, or site access policies, etc.) or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses. User authorization programs and lists of

authorized users for physical access are not required although they are an option to meet the security objective.

The objective is to control the physical access based on need as determined by the Responsible Entity. The need can be documented at the policy level for access to the site or systems, including LEAPs.. The requirement does not obligate an entity to specify a need for each access or authorization of a user for access.

Monitoring as a physical security control can be used as a complement or an alternative to access control. Examples of monitoring controls include, but are not limited to: (1) alarm systems to detect motion or entry into a controlled area, or (2) human observation of a controlled area. Monitoring does not necessarily require logging and maintaining logs but could include monitoring that physical access has occurred or been attempted (e.g., door alarm, or human observation, etc.). The monitoring does not need to be per low impact BES Cyber System but should be at the appropriate level to meet the security objective.

Requirement R2, Attachment 1, Section 3 – Electronic Access Controls

Section 3 requires the establishment of boundary protectionselectronic access controls for *assets containing low impact BES Cyber Systems*, also referred to herein as ("BES assets") when the low impact BES Cyber Systems have bi-directional external routable protocol communication (LERC) or Dial-up Connectivity is present to devices external toor from the asset containing the low impact BES Cyber Systems.System(s). The establishment of boundary protectionselectronic access controls is intended to control communication either into the asset containing low impact BES Cyber System(s) or to the low impact BES Cyber System itself to reduce the risks associated with uncontrolled communication using routable protocols or Dial-up Connectivity. The term "electronic access control" is used in the general sense, i.e., to control access, and not in the specific technical sense requiring authentication, authorization, and auditing. The Responsible Entity is not required to establish LERC communication or a LEAP if there is no bi-directional routable protocol communication or In the case where there is no LERC or Dial-up Connectivity present. In the case where there is no external bi-directional routable protocol communication, the Responsible Entity can document the absence of such communication in its low impact cyber security plan(s).

When identifying electronic access controls, Responsible Entities are provided flexibility in the selection of the controls that meet their operational needs while meeting the security objective of allowing only necessary electronic access to low impact BES Cyber Systems.

In essence, Responsible Entities are to determine LERC or Dial-up Connectivity for their BES assets and then, if present, document and implement electronic access control(s).

Determining LERC

The defined terms LERC and LEAP are term Low Impact External Routable Communication (LERC) is used to avoid confusion with the similar terms term External Routable Connectivity (ERC) used for high and medium impact BES Cyber Systems (e.g., External Routable Connectivity (ERC) or as these terms are different concepts. The input to this requirement from CIP-002 is a list of assets containing low impact BES Cyber Systems, therefore LERC is an attribute of a BES asset and involves routable protocol communications to or from the BES asset (crossing the

asset boundary) without regard to connectivity to Cyber Assets within the BES asset. ERC on the other hand is an attribute of an individual high or medium impact BES Cyber System and is relative to an Electronic ~~Access Point (EAP)). To future-proof the standards, and in~~Security Perimeter (ESP).

With LERC being a BES asset level attribute, it is used as a higher level filter to exclude from further consideration those assets containing low impact BES Cyber Systems that have no routable protocol communications to them from outside the BES asset. Responsible Entities can then concentrate their electronic access control efforts on those BES assets that do have LERC. However, this also means that LERC can exist for a BES asset even if there is no routable protocol connectivity to any low impact BES Cyber System within the BES asset.

In order to avoid future technology issues, the ~~definitions~~LERC definition specifically ~~exclude "point-to-point~~excludes communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between ~~Transmission station or substation~~non-Control Center BES assets containing low impact BES Cyber Systems~~,"~~, such as IEC 61850 messaging. This does not exclude Control Center to field communication but rather excludes the communication between the intelligent electronic devices ~~themselves.~~(e.g. relays) in the field. A Responsible Entity using this technology is not expected to implement ~~a LEAP~~the electronic access controls noted herein. This exception was included so as not to inhibit the functionality of the time-sensitive requirements related to this technology nor to preclude the use of such time-sensitive reliability enhancing functions if they use a routable protocol in the future.

Determining Asset Boundary

As LERC is a BES asset level attribute, it involves a determination by the Responsible Entity of a BES asset boundary for their assets containing low impact BES Cyber Systems. This boundary will vary by BES asset type (Control Center, substation, generation resource) and the specific configuration of the BES asset. The intent is for the Responsible Entity to define the BES asset boundary such that the low impact BES Cyber System(s) that are located at the BES asset are contained within the BES asset boundary. This is strictly for determining what constitutes the BES "asset" and for determining which routable protocol communications and networks are *internal* or *inside* or *local* to the BES asset and which are *external to or outside* the BES asset. This is not an Electronic Security Perimeter or Physical Security Perimeter as defined for medium and high impact BES Cyber Systems. For the asset containing low impact BES Cyber System(s), the BES asset boundary is synonymous to the concept of a "logical border" demarcation where routable protocol communication (e.g. LERC) enters and exits the BES asset containing the low impact BES Cyber System. Some examples of ways a Responsible Entity may determine BES asset boundaries are:

- For Control Centers
  - Designated areas (room(s) or floor(s)) if the Control Center is located within a larger building.
  - A building if in a dedicated building on a shared campus.

- The property/fence line if the Control Center is a dedicated facility on dedicated property.

- For substations, this could be the property/fence line or the control house.
- For generation resources:
  - Fossil/hydro generating facilities: This could be the property/fence line. If pumps or wells or other equipment that are part of the plant asset are outside the property line, then the BES asset boundary could expand to accommodate all that is considered part of the plant.
  - Solar farms: This could be the property line(s) or fence(s) surrounding all solar panels and interconnection facilities.
  - Wind farms: This could be the collection of individual turbines plus the equipment needed for interconnection.
  - Cogeneration facilities: This could be the identified portion of the larger plant that performs generation.

Determining Electronic Access Controls

Once a Responsible Entity has determined that LERC exists at the BES asset boundary, the Responsible Entity documents and implements its chosen electronic access control(s). The control(s) must allow only "necessary" access as determined by the Responsible Entity and they need to be able to explain the reasons for the electronic access permitted with their electronic access controls. The reasoning for the "necessary" access controls can be documented within the Responsible Entity's cyber security plan(s) or other policies or procedures associated with the electronic access controls.

Concept Diagrams

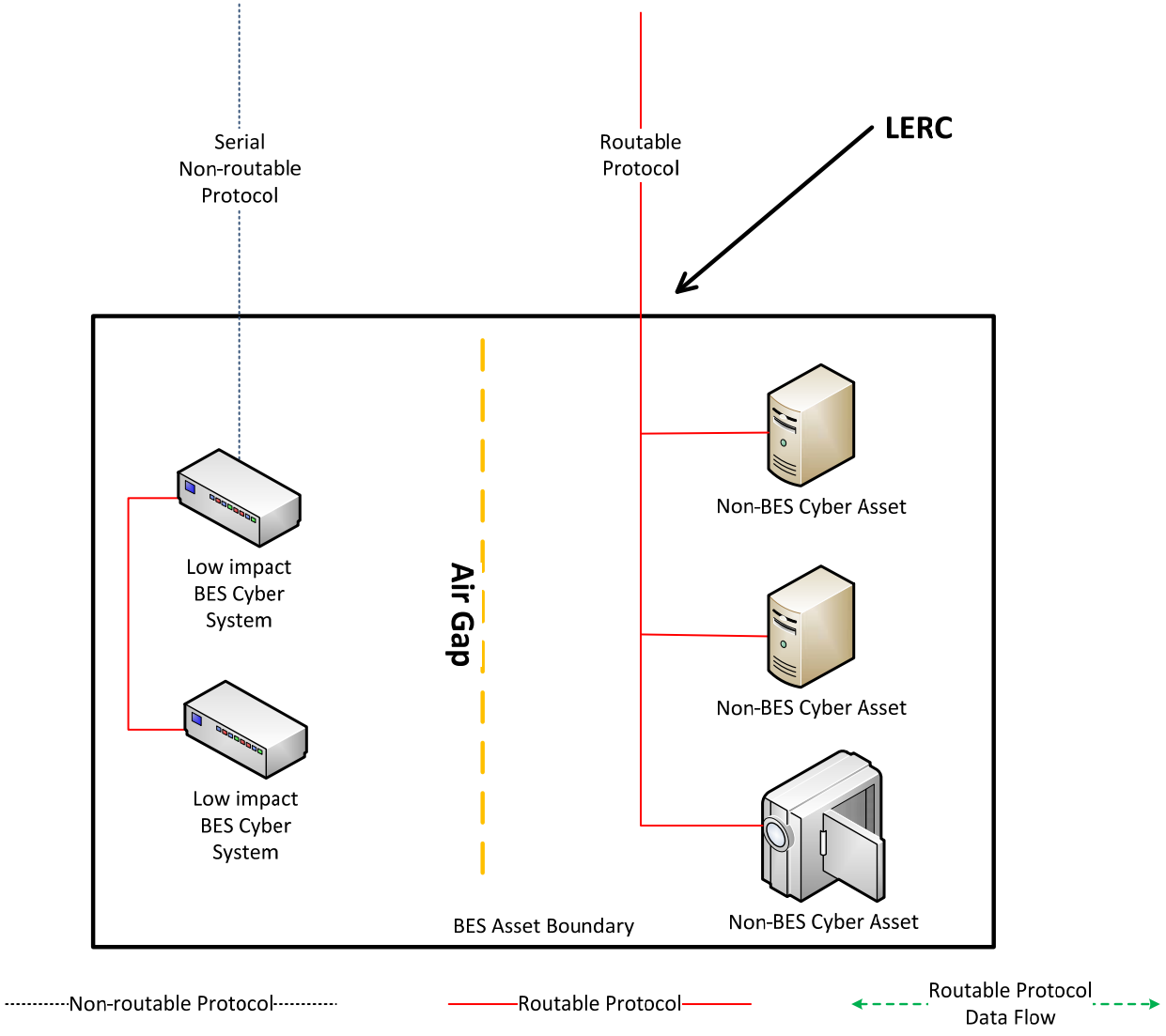
The diagrams on the following pages are provided as examples to illustrate various electronic access controls at a conceptual level. Regardless of the concepts or configurations chosen by the Responsible Entity, the security objective of permitting only necessary access to low impact BES Cyber Systems must be met when there is LERC to a BES asset.

NOTE:

- This is not an exhaustive list of applicable concepts.
- LERC is present in each diagram.
- The same legend is used in each diagram; however, the diagram may not contain all of the articles represented in the legend.
- The term "BES Asset Boundary" is capitalized in the diagrams but it is not a defined term.

LERC Reference Model 1 – Physical Isolation

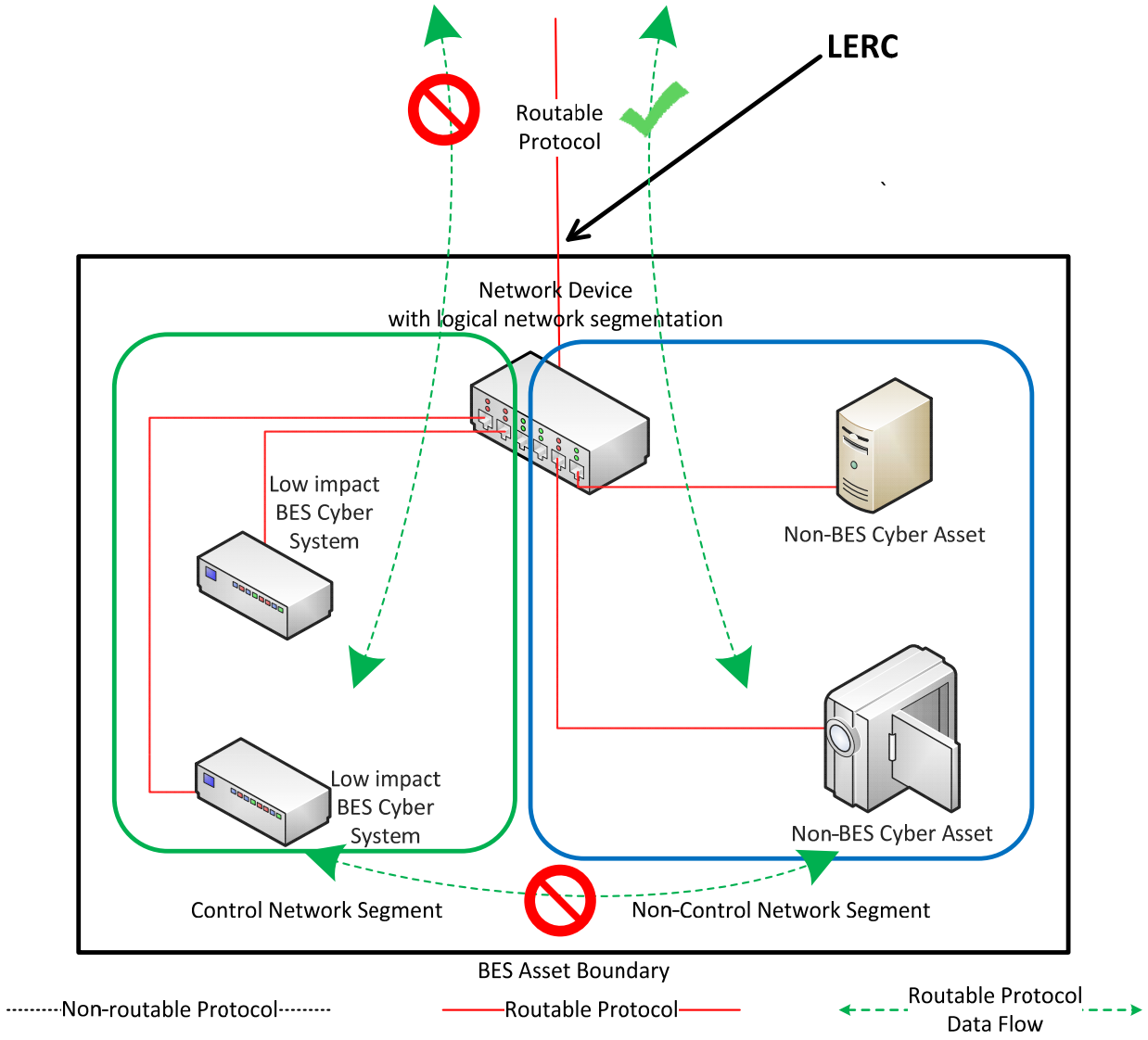
The Responsible Entity may choose to physically isolate the low impact BES Cyber System(s) from the LERC. This control is commonly referred to as an 'air gap'. The serial non-routable protocol connection and the routable protocol LERC are completely isolated from each other. There is no equipment shared with the low impact BES Cyber System(s).



Reference Model 1

LERC Reference Model 2 – Logical Isolation

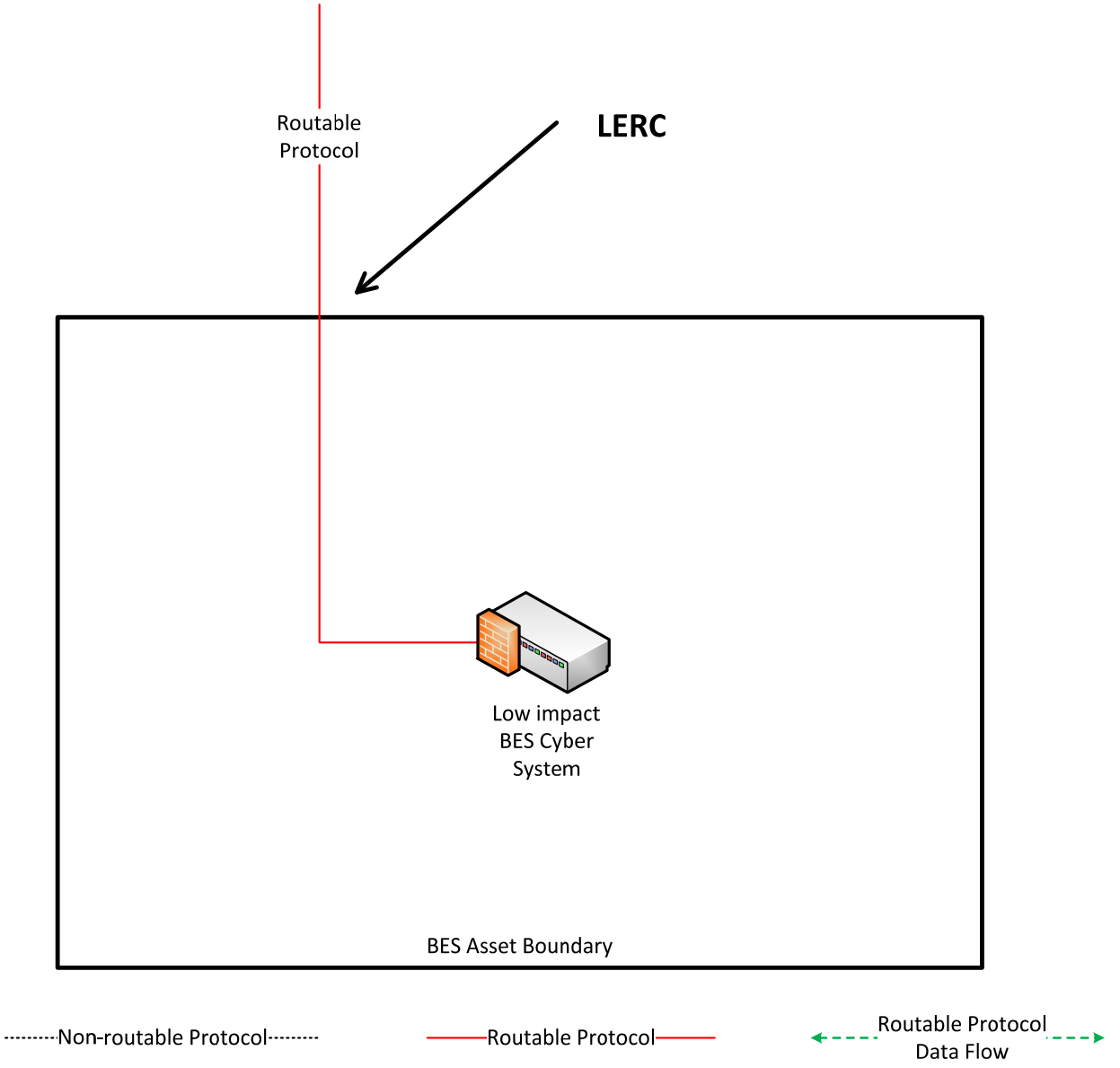
The Responsible Entity may choose to logically isolate the low impact BES Cyber System(s) from the LERC. The low impact BES Cyber System(s) is on an isolated network segment with logical controls preventing routable protocol communication into or out of the network containing the low impact BES Cyber System(s).



Reference Model 2

LERC Reference Model 3 – Host-based Inbound & Outbound Access Permissions

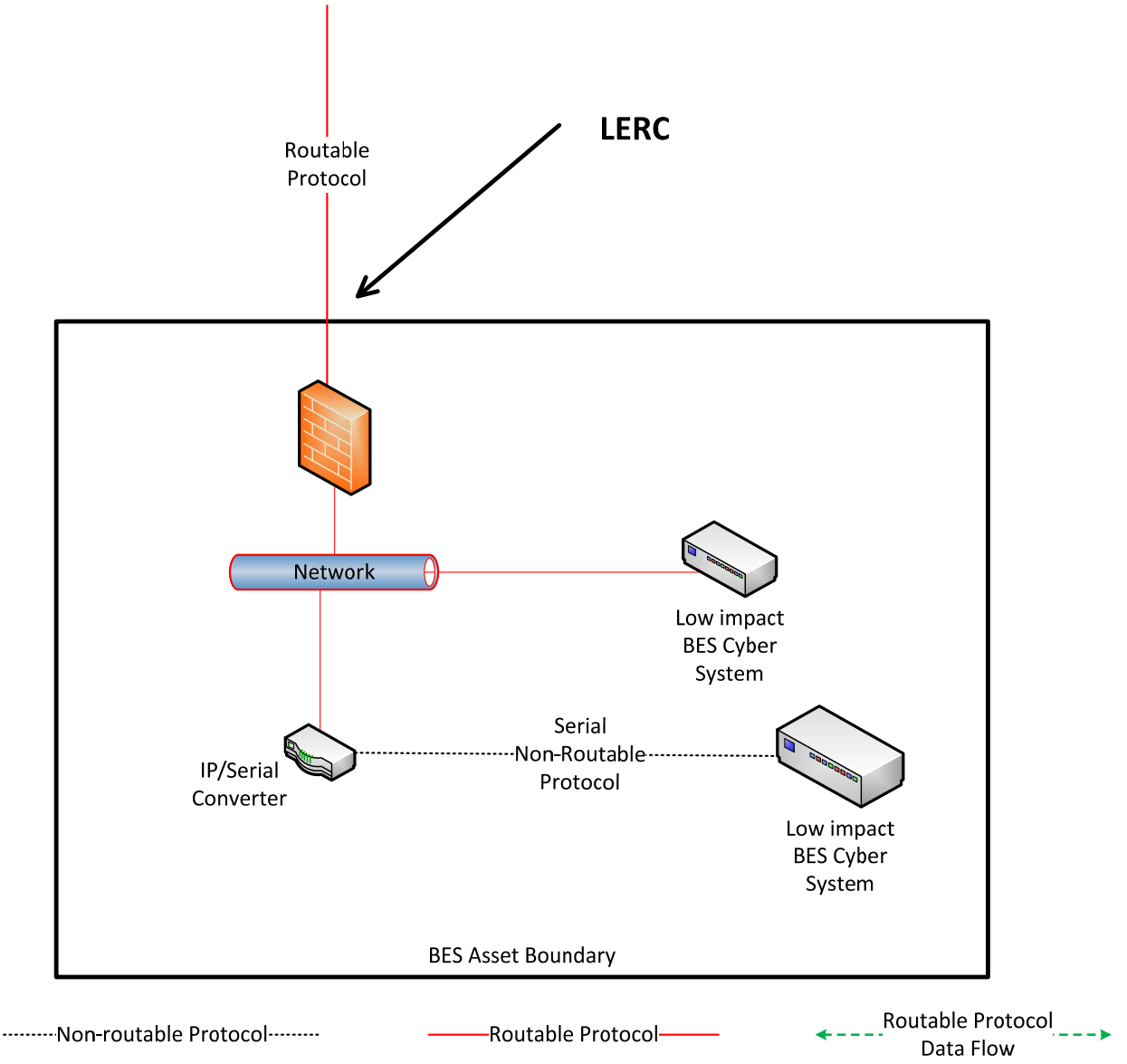
The Responsible Entity may choose to utilize a host-based firewall technology on the low impact BES Cyber System(s) that manages electronic access permission so that only necessary inbound and outbound routable protocol access is allowed to the low impact BES Cyber System(s).



Reference Model 3

LERC Reference Model 4 – Network-based Inbound & Outbound Access Permissions

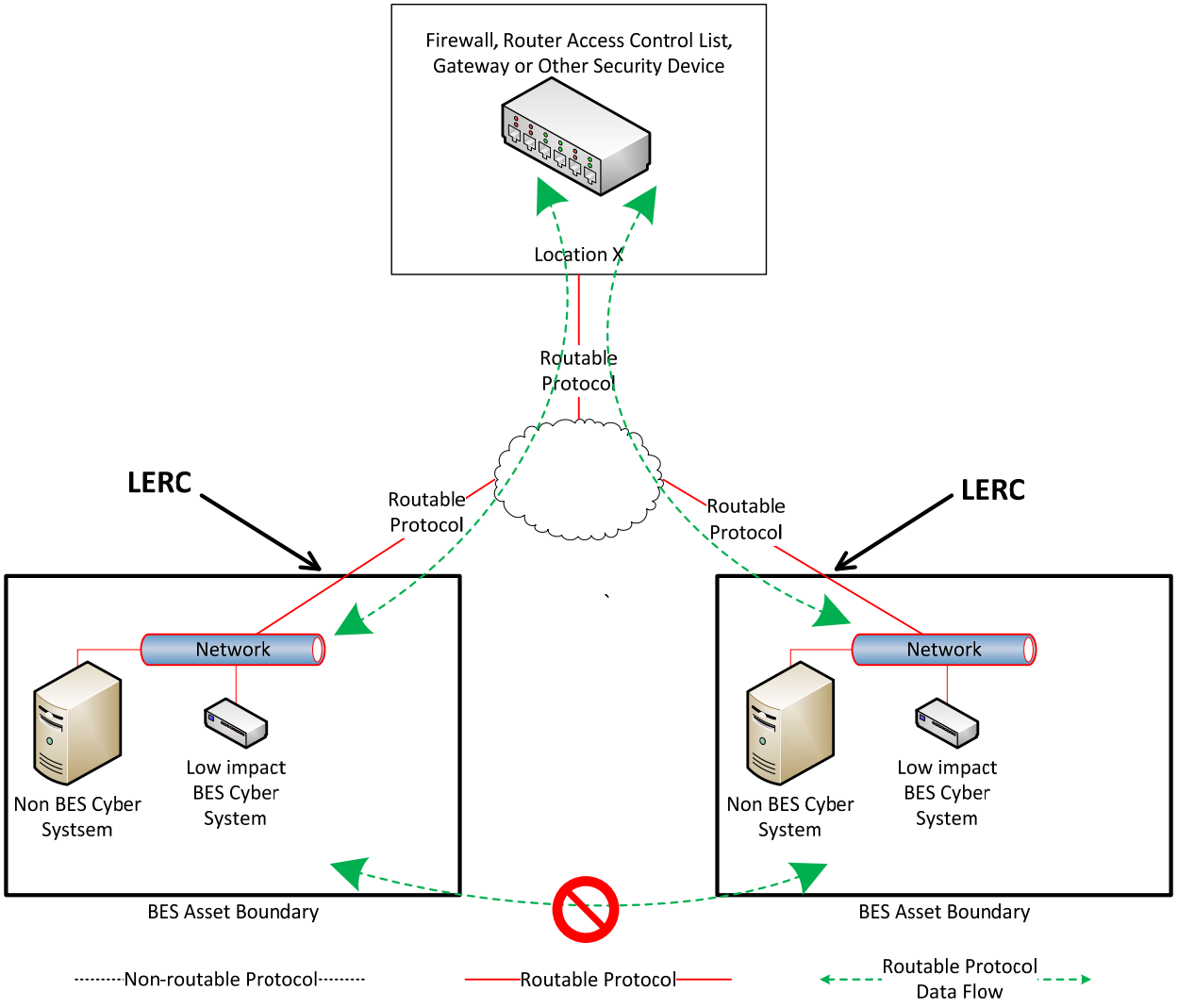
The Responsible Entity may choose to utilize a security device that permits only necessary access to the low impact BES Cyber System(s) within the BES asset. In this example, two low impact BES Cyber Systems are accessed over the LERC as the IP/Serial converter is continuing the same communications session from device(s) outside the BES asset boundary to the low impact BES Cyber Systems. The security device provides the electronic access controls to permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber Systems.



Reference Model 4

LERC Reference Model 5 – Centralized Network-based Inbound & Outbound Access Permissions

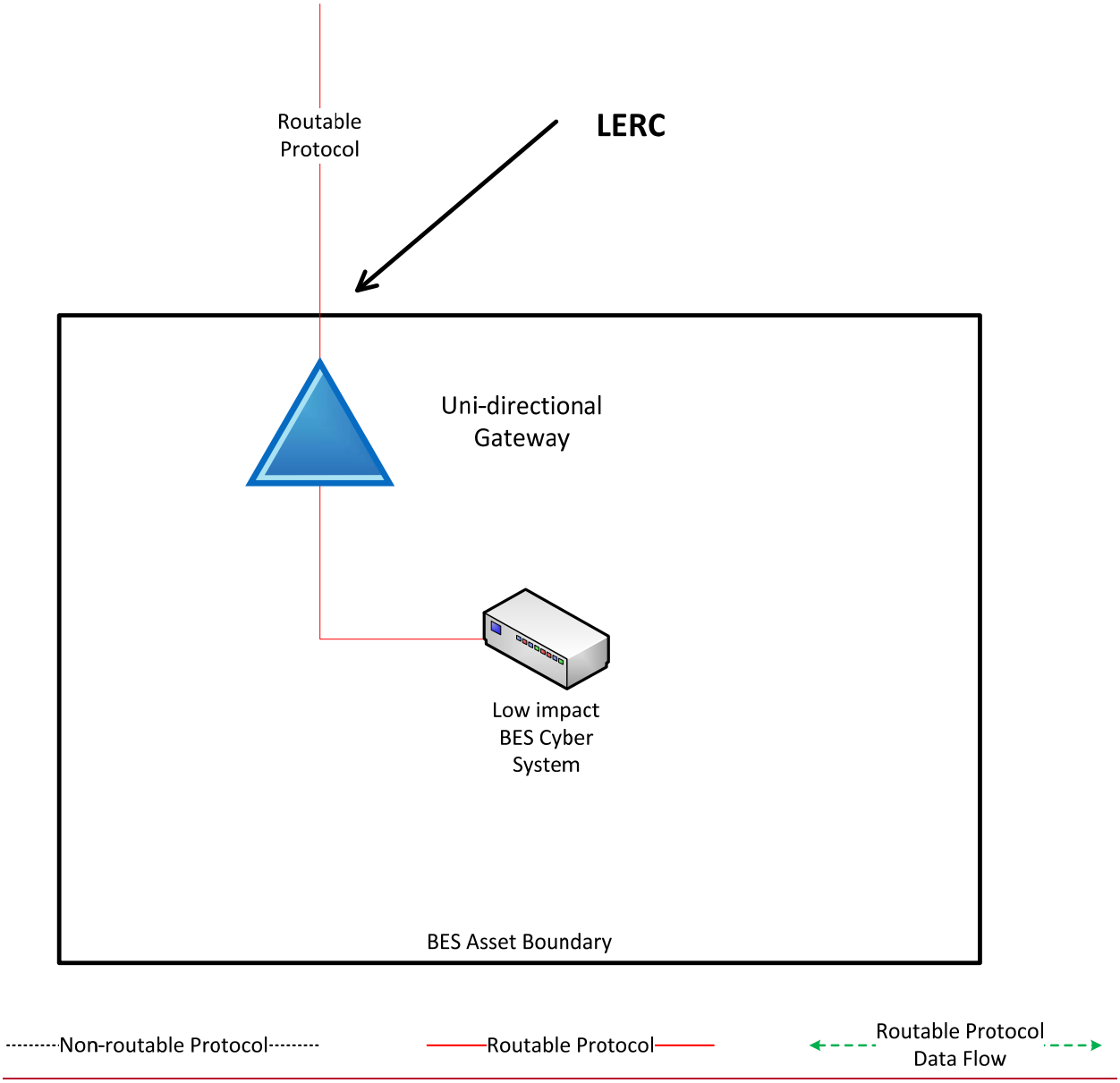
The Responsible Entity may choose to utilize a security device at a centralized location that may or may not be another BES asset. The electronic access control(s) do not necessarily have to reside inside the asset containing the low impact BES Cyber System(s). A security device is in place at "Location X" to act as the electronic access control and permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber System(s). Care should be taken that electronic access to or between each BES asset is through the electronic access controls at the centralized location.



Reference Model 5

LERC Reference Model 6 – Uni-directional Gateway

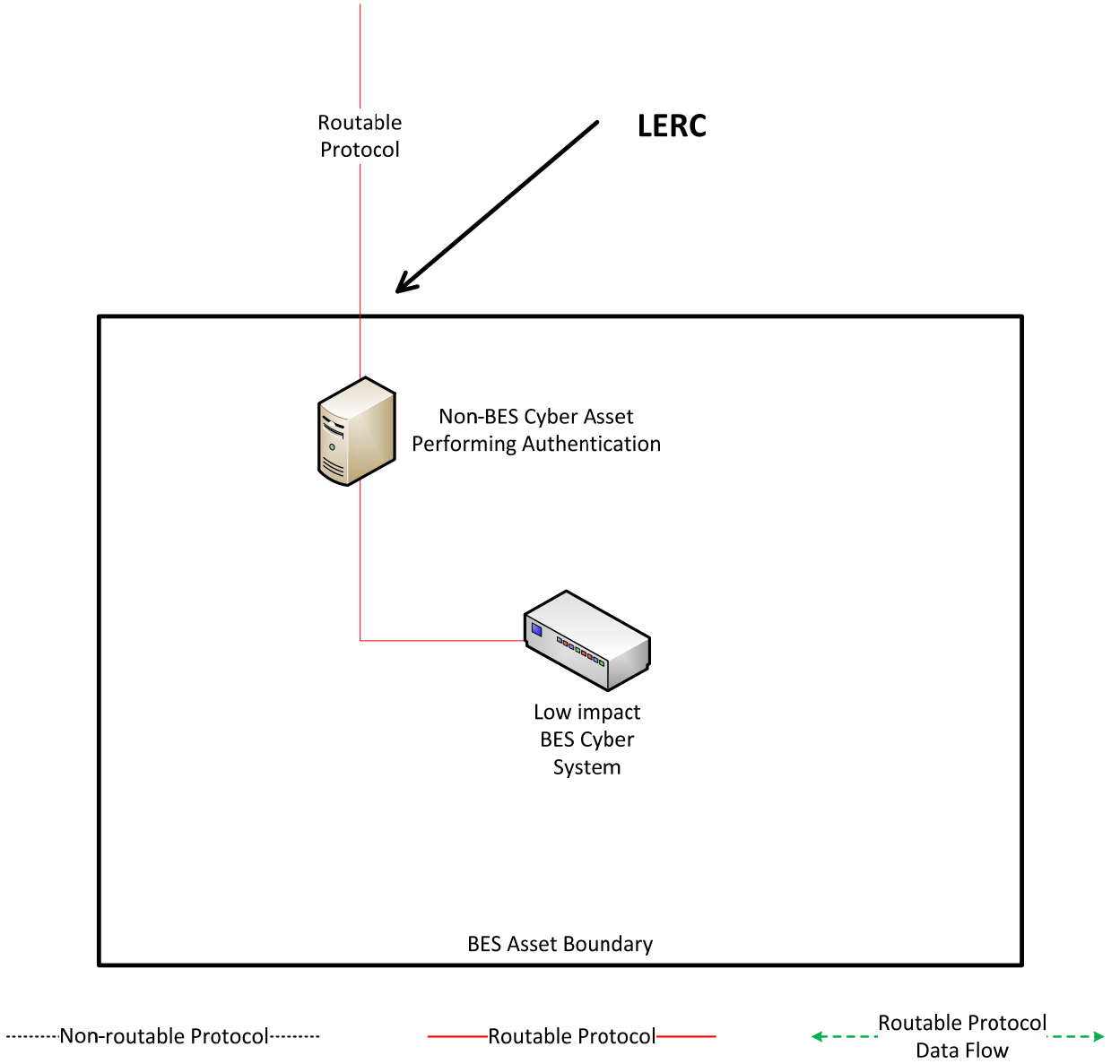
The Responsible Entity may choose to utilize a uni-directional gateway as the electronic access control. The low impact BES Cyber System(s) is not accessible (data cannot flow into the low impact BES Cyber System) from the LERC due to the implementation of a "one-way" (uni-directional) path for data to flow across the BES asset boundary.



Reference Model 6

LERC Reference Model 7 – User Authentication

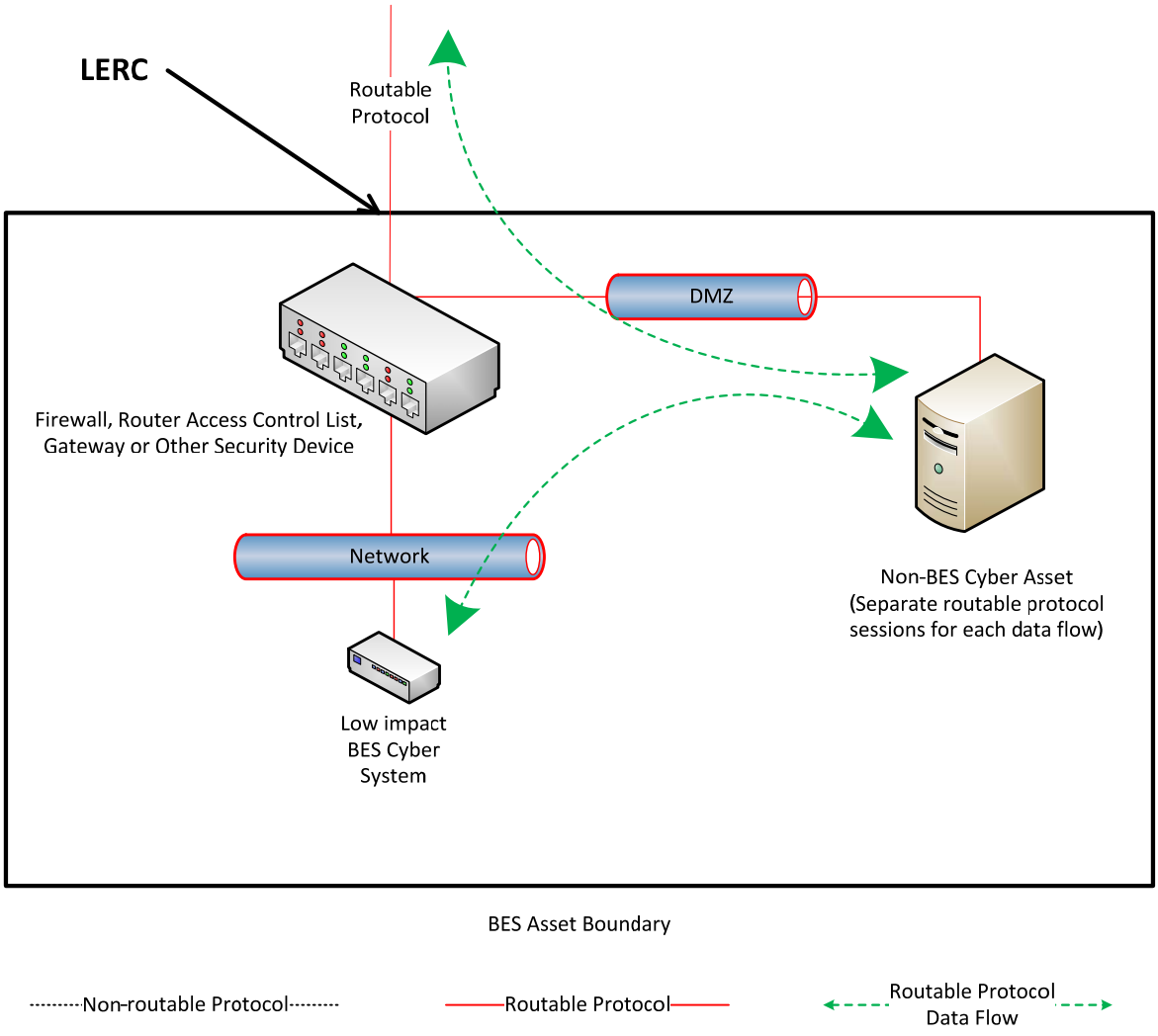
The Responsible Entity may choose to utilize a non-BES Cyber Asset between the network outside the BES asset boundary and the low impact BES Cyber System to perform user authentication for interactive access. The non-BES Cyber Asset would require authentication before establishing a new connection to the low impact BES Cyber System. The electronic access control depicted in this reference model may not meet the security objective for controlling device-to-device communication across the LERC depending on the specific system configuration in place.



Reference Model 7

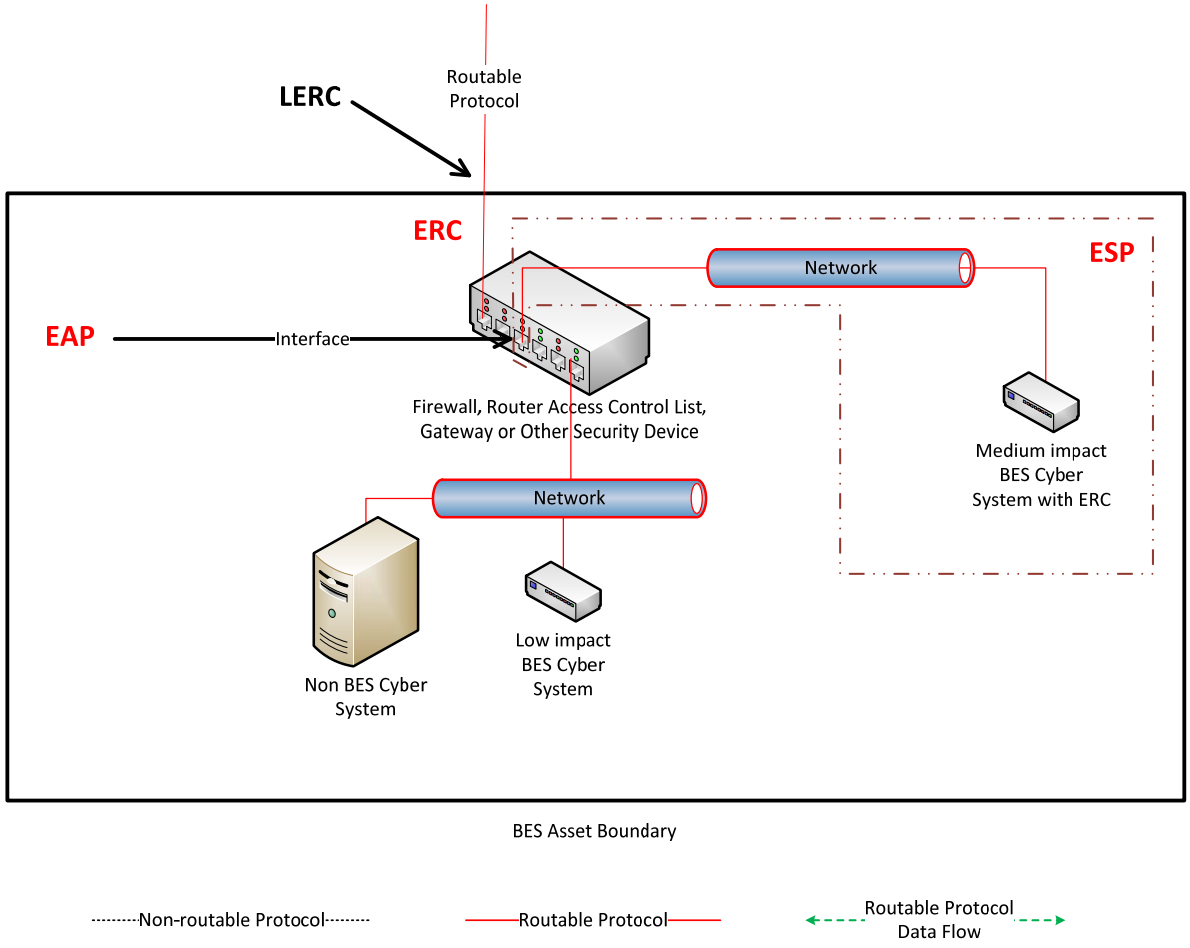
LERC Reference Model 8 – Session Termination

The Responsible Entity may choose to terminate routable protocol application sessions at a non-BES Cyber Asset inside the asset containing the low impact BES Cyber System(s) such that a separate application session is established to the low impact BES Cyber System(s) from the non-BES Cyber Asset (the routable session from outside the BES asset). The Responsible Entity may choose to authenticate access at a non-BES Cyber Asset either outside BES asset boundary or inside the asset containing the low impact BES Cyber System(s) such that unauthenticated access to the low impact BES Cyber System(s) is prohibited. The non-BES Cyber Asset sits on a demilitarized zone (DMZ) between the network outside the BES asset boundary and the low impact BES Cyber System(s). The non-BES Cyber Asset in the DMZ terminates the routable protocol session and establishes a new session to the low impact BES Cyber System(s). Additionally, a security device permits traffic from the network outside the BES asset boundary to flow only to and from the non-BES Cyber Asset in the DMZ (the routable session to the low impact BES Cyber System).



LERC Reference Model 9 – LERC and ERC

There is both LERC and ERC present in this reference model because there is at least one medium impact BES Cyber System and one low impact BES Cyber System within the BES asset. The Responsible Entity may choose to leverage an interface on the medium impact Electronic Access Control or Monitoring Systems (EACMS) device to provide electronic access controls for the LERC. The EACMS is therefore performing multiple functions – as a medium impact EACMS and as implementing low impact electronic access controls.



Reference Model 9

When determining whether there is LERC to the low impact BES Cyber System, the definition uses the phrases "direct user-initiated interactive access or a direct device-to-device connection to a low impact BES Cyber System(s) from a Cyber Asset outside the asset containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection." The intent of "direct" in the definition is to indicate LERC exists if a person is sitting at another device outside of the asset containing the low impact BES Cyber System, and the person can connect to logon, configure, read, or interact, etc. with the low impact BES Cyber System using a bi-directional routable protocol within a single end-to-end protocol session even if there is a serial-to-routable protocol conversion. The reverse case would also be LERC, in which the individual sits at the low impact BES Cyber System and connects to a device outside the asset containing low impact BES Cyber Systems using a single end-to-end bi-directional routable protocol session. Additionally, for "device-to-device connection," LERC exists if the Responsible Entity has devices outside of the asset containing the low impact BES Cyber System sending or receiving bi-directional routable communication to or from the low impact BES Cyber System.

When identifying a LEAP, Responsible Entities are provided flexibility in the selection of the interface on a Cyber Asset that controls the LERC. Examples include, but are not limited to, the internal (facing the low impact BES Cyber Systems) interface on an external or host-based firewall, the internal interface on a router that has implemented an access control list (ACL), or other security device. The entity also has flexibility with respect to the location of the LEAP. LEAPs are not required to reside at the asset containing the low impact BES Cyber Systems. Furthermore, the entity is not required to establish a unique physical LEAP per asset containing low impact BES Cyber Systems. Responsible Entities can have a single Cyber Asset containing multiple LEAPs that controls the LERC for more than one asset containing low impact BES Cyber Systems. Locating the Cyber Asset with multiple LEAPs at an external location with multiple assets containing low impact BES Cyber Systems "behind" it, however, should not allow uncontrolled access to assets containing low impact BES Cyber Systems sharing a Cyber Asset containing the LEAP(s).

In Reference Model 4, the communication flows through an IP/Serial converter. LERC is correctly identified in this Reference Model because the IP/Serial converter in this instance is doing nothing more than extending the communication between the low impact BES Cyber System and the Cyber Asset outside the asset containing the low impact BES Cyber System. In contrast, Reference Model 6 has placed a Cyber Asset that performs a complete break or interruption that does not allow the user or device data flow to directly communicate with the low impact BES Cyber System. The Cyber Asset in Reference Model 6 is preventing extending access to the low impact BES Cyber System from the Cyber Asset outside the asset containing the low impact BES Cyber System. The intent is that if the IP/Serial converter that is deployed only does a "pass-through" of the data flow communication, then that "pass-through" data flow communication is LERC and a LEAP is required. However, if that IP/Serial converter performs some type of authentication in the data flow at the asset containing the low impact BES Cyber System before the communication can be sent to the low impact BES Cyber System, then that type of IP/Serial converter implementation is not LERC.

~~A Cyber Asset that contains interface(s) that only perform the function of a LEAP does not meet the definition of Electronic Access Control or Monitoring System (EACMS) associated with medium or high impact BES Cyber Systems and is not subject to the requirements applicable to an EACMS. However, a Cyber Asset may contain some interfaces that function as a LEAP and other interfaces that function as an EAP for high or medium impact BES Cyber Systems. In this case, the Cyber Asset would also be subject to the requirements applicable to the EACMS associated with the medium or high impact BES Cyber Systems.~~

~~Examples of sufficient access controls may include:~~

- ~~Any LERC for the asset passes through a LEAP with explicit inbound and outbound access permissions defined, or equivalent method by which both inbound and outbound connections are confined to only those that the Responsible Entity deems necessary (e.g., IP addresses, ports, or services).~~
- ~~As shown in Reference Model 1 below, the low impact BES Cyber System has a host-based firewall that is controlling the inbound and outbound access. In this model, it is also possible that the host-based firewall could be on a non-BES Cyber Asset. The intent is that the host-based firewall controls the inbound and outbound access between the low impact BES Cyber System and the Cyber Asset in the business network.~~
- ~~As shown in Reference Model 5 below, a non-BES Cyber Asset has been placed between the low impact BES Cyber System on the substation network and the Cyber Asset in the business network. The expectation is that the non-BES Cyber Asset has provided a "protocol break" so that access to the low impact BES Cyber System is only from the non-BES Cyber Asset that is located within the asset containing the low impact BES Cyber System.~~

Dial-up Connectivity

Dial-up Connectivity to a low impact BES Cyber System is set to dial out only (no auto-answer) to a preprogrammed number to deliver data. Incoming Dial-up Connectivity is to a dialback modem, a modem that must be remotely controlled by the control center or control room, has some form of access control, or the low impact BES Cyber System has access control.

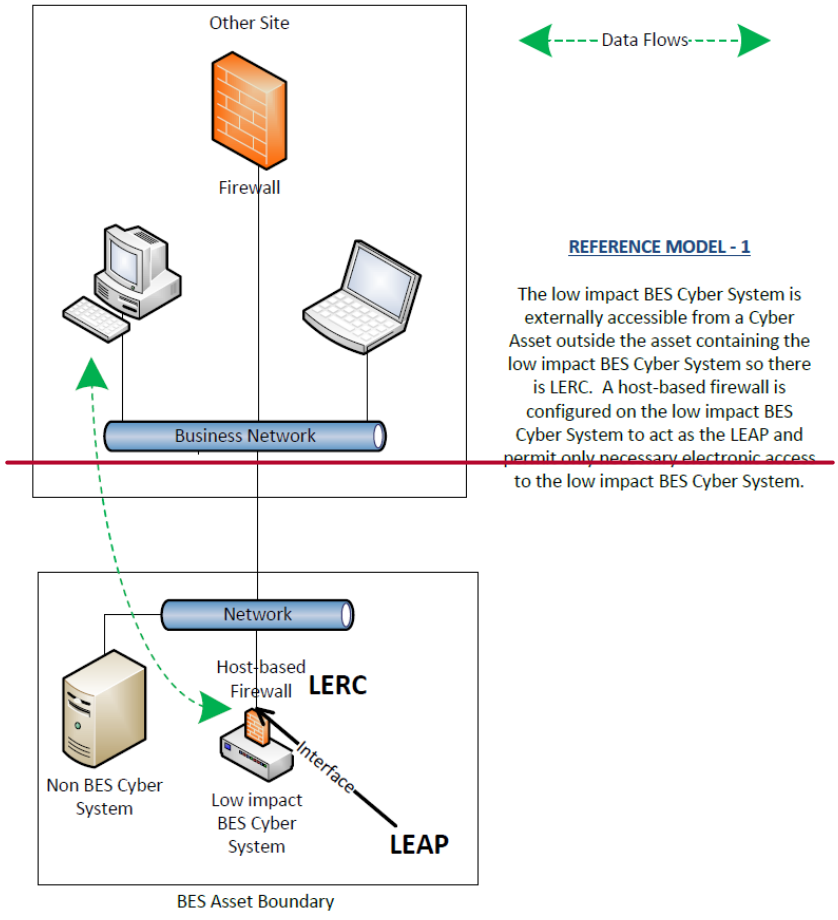
Insufficient Access Controls

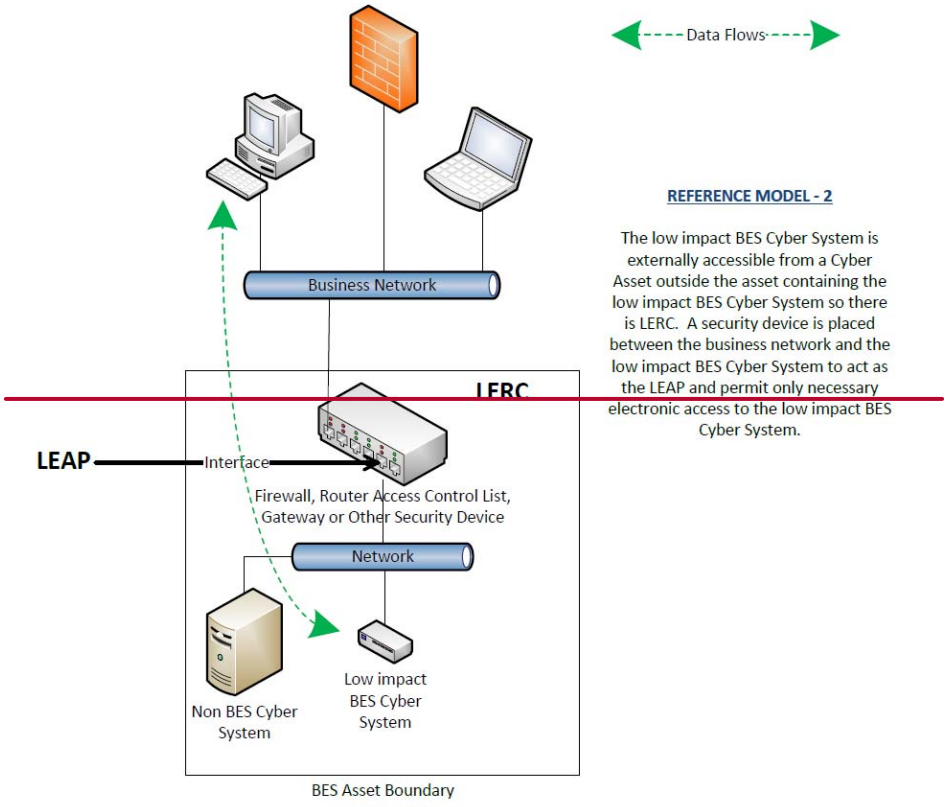
Some examples of situations that would lack sufficient access controls to meet the intent of this requirement include:

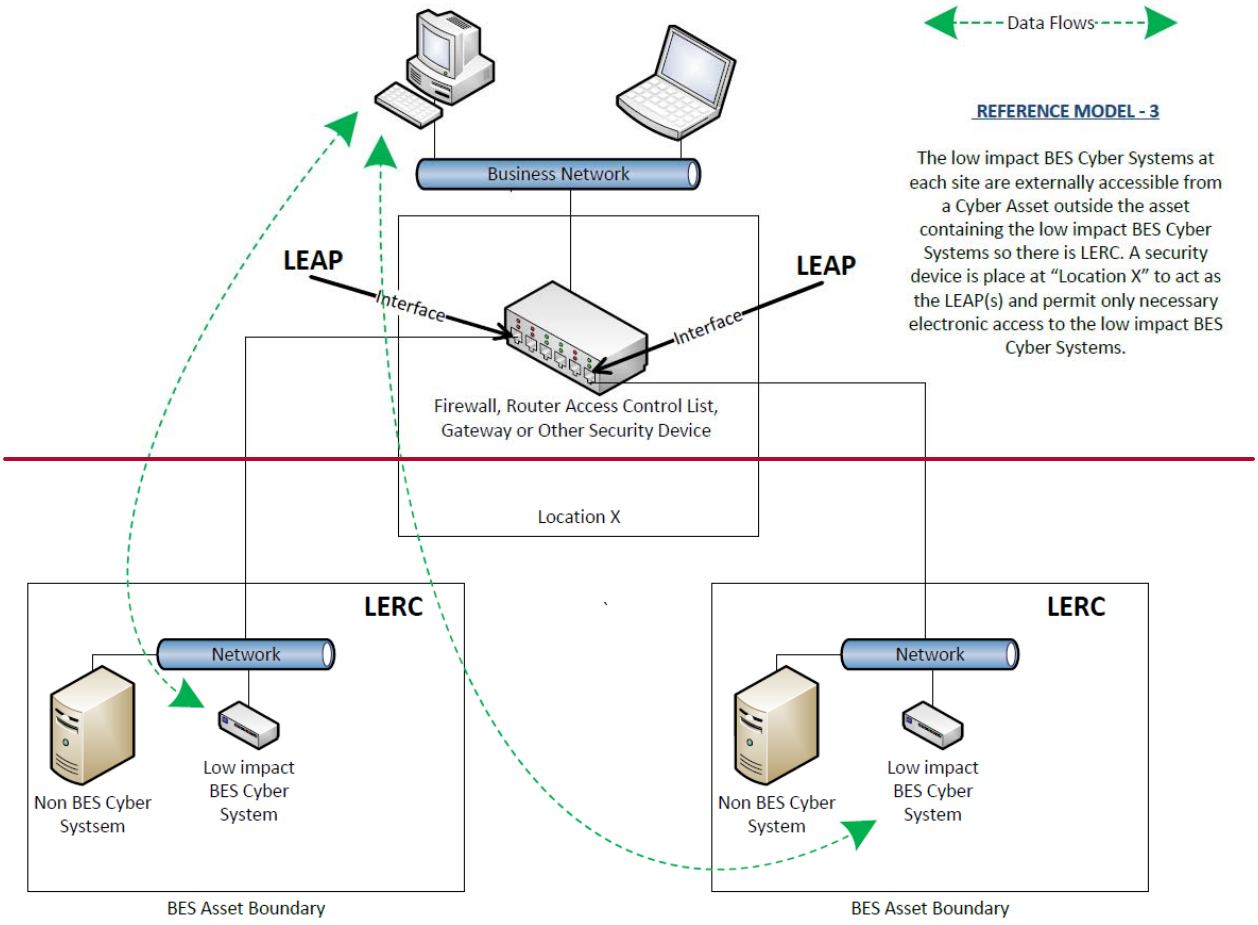
- An asset has Dial-up Connectivity and a low impact BES Cyber System is reachable via an auto-answer modem that connects any caller to the Cyber Asset that has a default password. There is no practical access control in this instance.
- An asset has LERC due to a BES Cyber System within it having a wireless card on a public carrier that allows the BES Cyber System to be reachable via a public IP address. In essence, low impact BES Cyber Systems should not be accessible from the Internet and search engines such as Shodan.
- ~~In Reference Model 5, using just dual~~Dual-homing or multiple-network interface cards without disabling IP forwarding in the non-BES Cyber Asset within the DMZ to provide

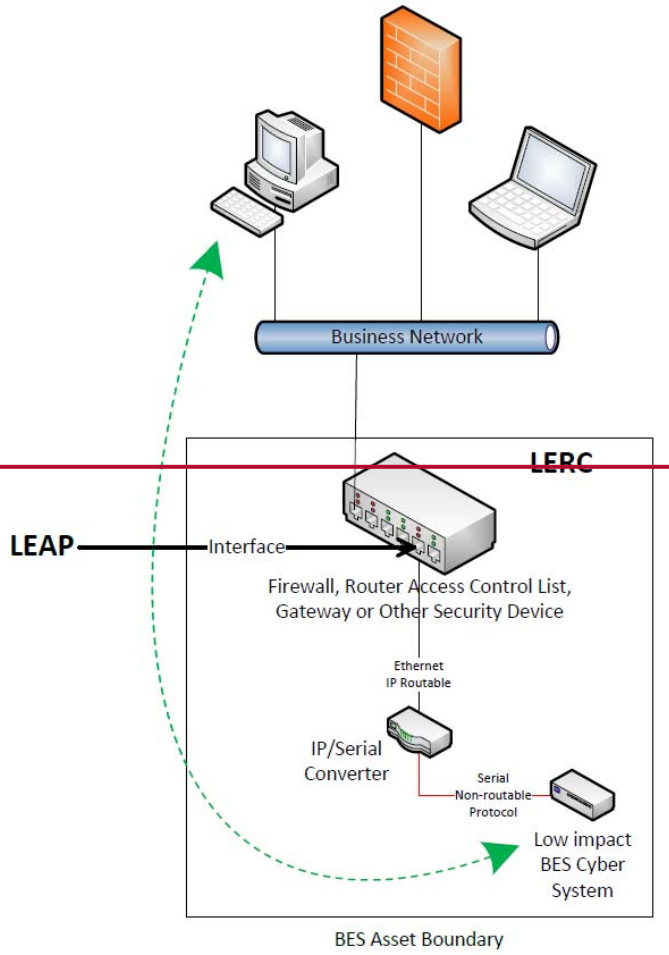
separation between the low impact BES Cyber System(s) and the ~~business~~external network would not meet the intent of "controlling" inbound and outbound electronic access assuming there was no other host-based firewall or other security ~~device~~devices on ~~that~~the non-BES Cyber Asset.

~~The following diagrams provide reference examples intended to illustrate how to determine whether there is LERC and for implementing a LEAP. While these diagrams identify several possible configurations, Responsible Entities may have additional configurations not identified below.~~




Data Flows
REFERENCE MODEL - 2
The low impact BES Cyber System is externally accessible from a Cyber Asset outside the asset containing the low impact BES Cyber System so there is LERC. A security device is placed between the business network and the low impact BES Cyber System to act as the LEAP and permit only necessary electronic access to the low impact BES Cyber System.
Business Network
LERC
LEAP
Interface
Firewall, Router Access Control List, Gateway or Other Security Device
Network
Non BES Cyber System
Low impact BES Cyber System
BES Asset Boundary

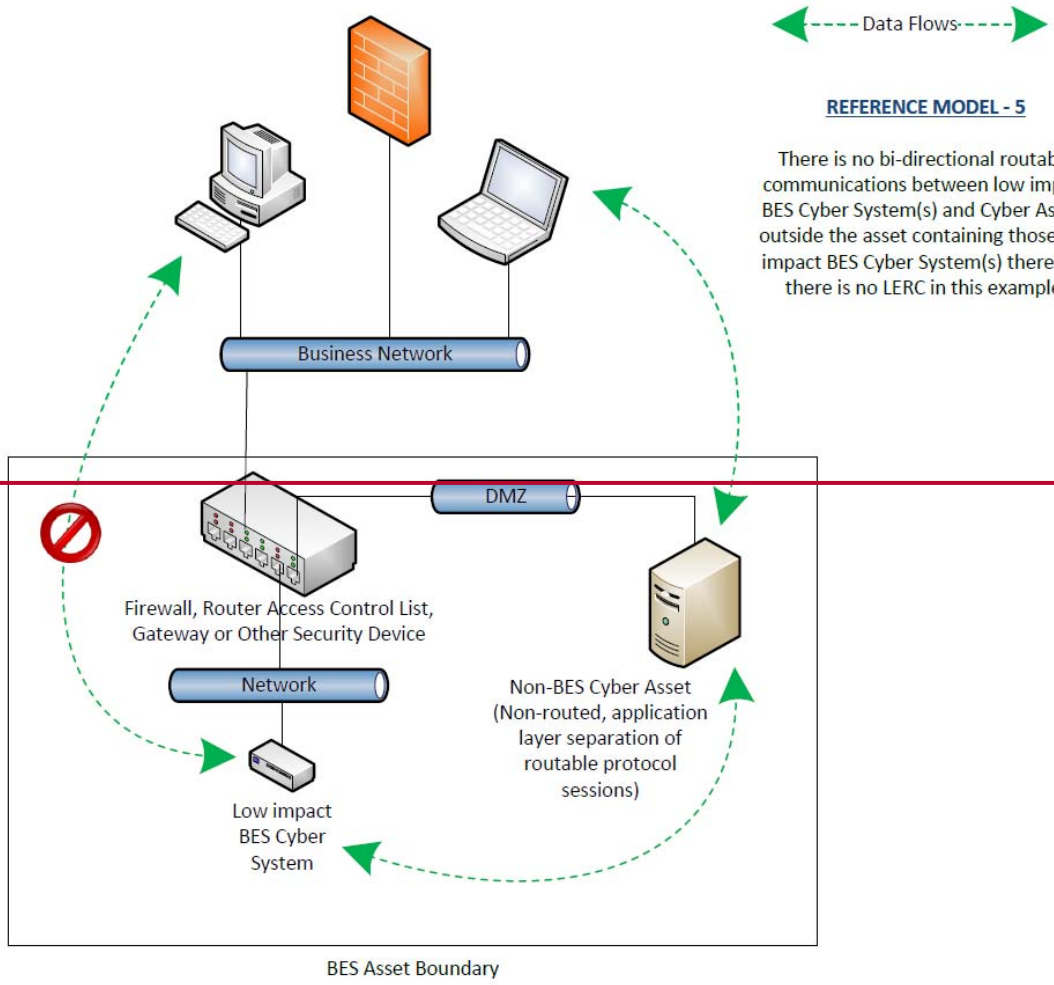

Data Flows
REFERENCE MODEL - 3
The low impact BES Cyber Systems at each site are externally accessible from a Cyber Asset outside the asset containing the low impact BES Cyber Systems so there is LERC. A security device is place at "Location X" to act as the LEAP(s) and permit only necessary electronic access to the low impact BES Cyber Systems.
Business Network
LEAP
Interface
LEAP
Interface
Firewall, Router Access Control List, Gateway or Other Security Device
Location X
LERC
Network
Non BES Cyber Systsem
Low impact BES Cyber System
BES Asset Boundary
LERC
Network
Non BES Cyber System
Low impact BES Cyber System
BES Asset Boundary

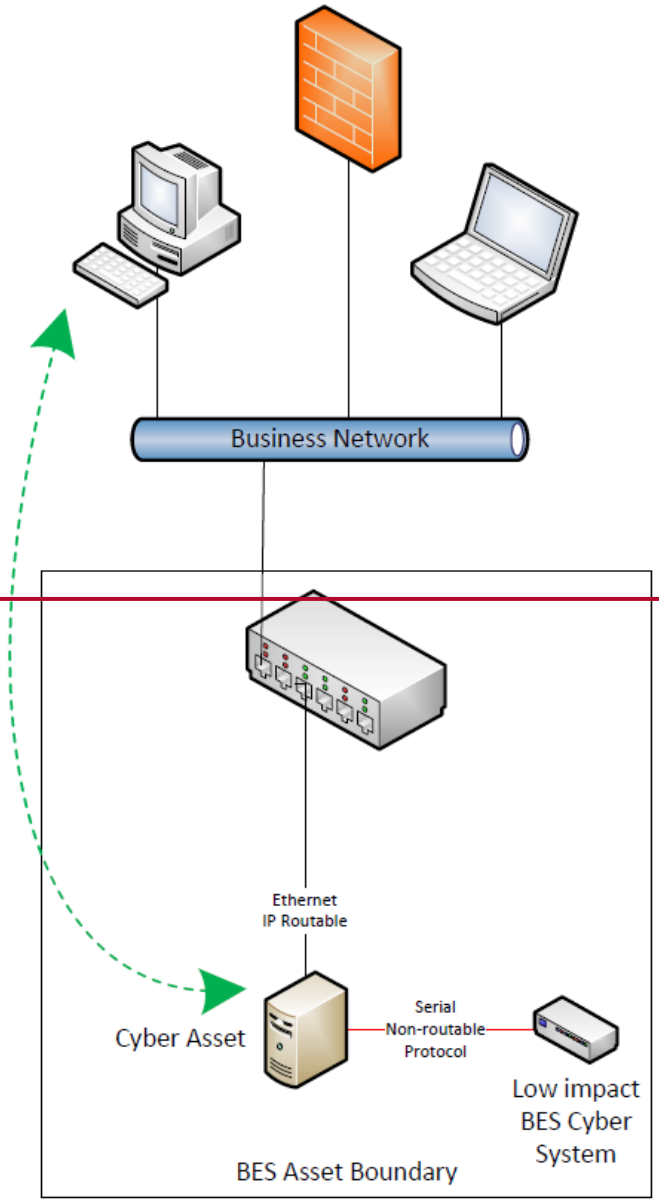


Data Flows

REFERENCE MODEL - 4

The low impact BES Cyber System is externally accessible from a Cyber Asset outside the asset containing the low impact BES Cyber System. There is LERC because the IP/Serial converter is extending the communication between the business network Cyber Asset and the low impact BES Cyber System is directly addressable from outside the asset. A security device is placed between the business network and the low impact BES Cyber System to permit only necessary electronic access to the low impact BES Cyber System.

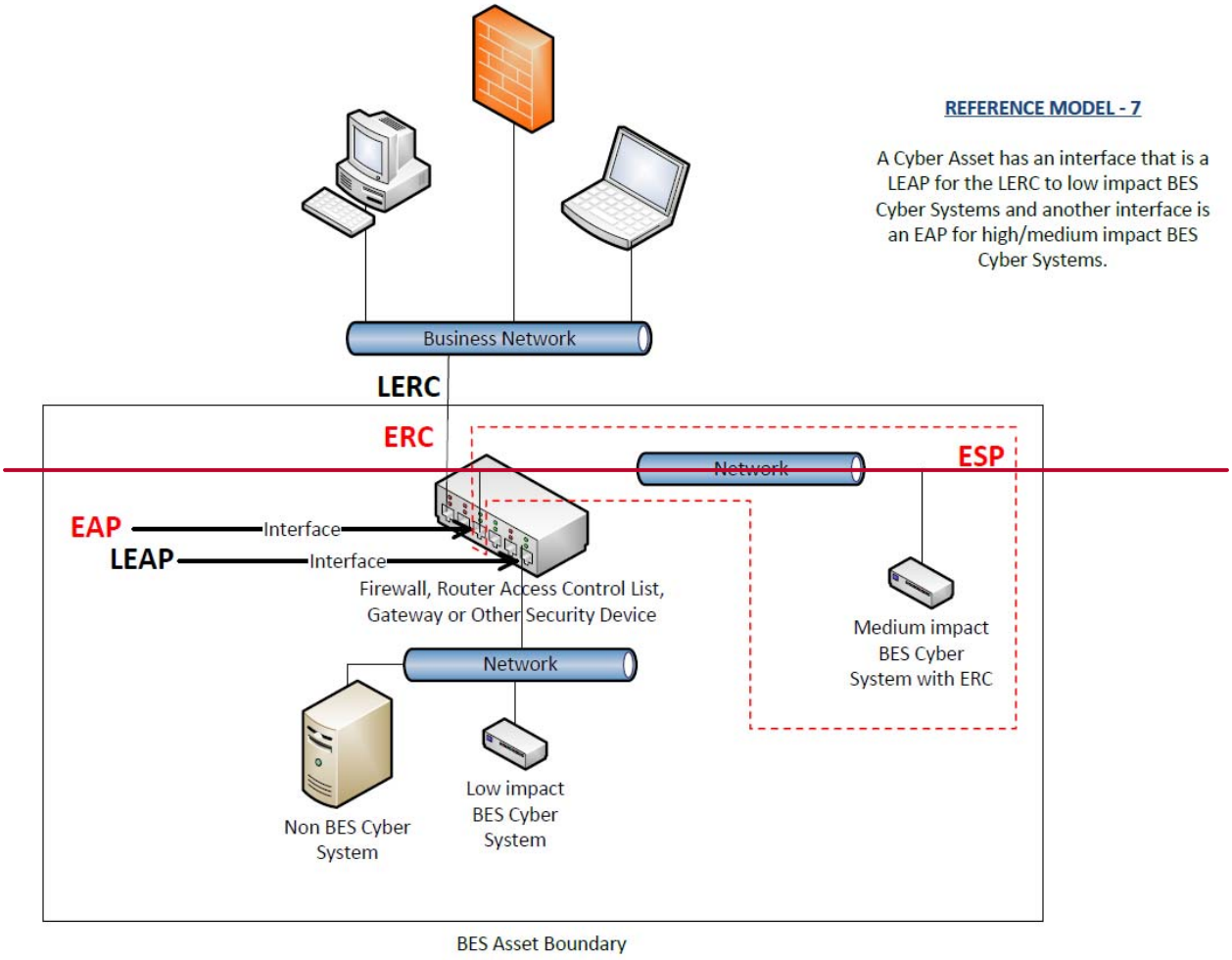

Data Flows
REFERENCE MODEL - 5
There is no bi-directional routable communications between low impact BES Cyber System(s) and Cyber Assets outside the asset containing those low impact BES Cyber System(s) therefore there is no LERC in this example.
Business Network
DMZ
Firewall, Router Access Control List, Gateway or Other Security Device
Network
Non-BES Cyber Asset (Non-routed, application layer separation of routable protocol sessions)
Low impact BES Cyber System
BES Asset Boundary



Data Flows

REFERENCE MODEL - 6

In this example, a Cyber Asset stops the direct access to the low impact BES Cyber System. There is a layer 7 application layer break or the Cyber Asset requires authentication and then establishes a new connection to the low impact BES Cyber System. There is no LERC in this example.



Requirement R2, Attachment 1, Section 4 – Cyber Security Incident Response

The entity should have one or more documented Cyber Security Incident response plan(s) that include each of the topics listed in Section 4. If, in the normal course of business, suspicious activities are noted at an asset containing low impact BES Cyber System(s), the intent is for the entity to implement a Cyber Security Incident response plan that will guide the entity in responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Entities are provided the flexibility to develop their Attachment 1, Section 4 Cyber Security Incident response plan(s) by asset or group of assets. The plans do not need to be on a per asset site or per low impact BES Cyber System basis. Entities can choose to use a single enterprise-wide plan to fulfill the obligations for low impact BES Cyber Systems.

The plan(s) must be tested once every 36 months. This is not an exercise per low impact BES Cyber Asset or per type of BES Cyber Asset but rather is an exercise of each incident response plan the entity created to meet this requirement. An actual Reportable Cyber Security Incident counts as an exercise as do other forms of tabletop exercises or drills. NERC-led exercises such as GridEx participation would also count as an exercise provided the entity's response plan is followed. The intent of the requirement is for entities to keep the Cyber Security Incident

response plan(s) current, which includes updating the plan(s), if needed, within 180 days following a test or an actual incident.

For low impact BES Cyber Systems, the only portion of the definition of Cyber Security Incident that would apply is, "A malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of a BES Cyber System." The other portion of that definition is not to be used to require ESPs and PSPs for low impact BES Cyber Systems.

Requirement R3:

The intent of CIP-003-~~6~~7, Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Reliability Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that the CIP Senior Manager will play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

Requirement R4:

As indicated in the rationale for CIP-003-~~6~~7, Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the intent is to afford the Responsible Entity significant flexibility to adapt this requirement to its existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records shows a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up-to-date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or the individual is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

Rationale:

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

Rationale for Requirement R1:

One or more security policies enable effective implementation of the requirements of the cyber security Reliability Standards. The purpose of policies is to provide a management and governance foundation for all requirements that apply to a Responsible Entity's BES Cyber

Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the requirements.

Annual review and approval of the cyber security policies ensures that the policies are kept-up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for Requirement R2:

In response to FERC Order No. 791, Requirement R2 requires entities to develop and implement cyber security plans to meet specific security control objectives for assets containing low impact BES Cyber System(s). The cyber security plan(s) covers four subject matter areas: (1) cyber security awareness; (2) physical security controls; (3) electronic access controls; and (4) Cyber Security Incident response. This plan(s), along with the cyber security policies required under Requirement R1, Part 1.2, provides a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Considering the varied types of low impact BES Cyber Systems across the BES, Attachment 1 provides Responsible Entities flexibility on how to apply the security controls to meet the security objectives. Additionally, because many Responsible Entities have multiple-impact rated BES Cyber Systems, nothing in the requirement prohibits entities from using their high and medium impact BES Cyber System policies, procedures, and processes to implement security controls required for low impact BES Cyber Systems, as detailed in Requirement R2, Attachment 1.

Responsible Entities will use their identified assets containing low impact BES Cyber System(s) (developed pursuant to CIP-002) to substantiate the sites or locations associated with low impact BES Cyber System(s). However, there is no requirement or compliance expectation for Responsible Entities to maintain a list(s) of individual low impact BES Cyber System(s) and their associated cyber assets or to maintain a list of authorized users.

Rationale for Requirement R3:

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the Glossary of Terms used in NERC Reliability Standards so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has "the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards" which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the CIP

Senior Manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.

Rationale for Requirement R4:

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for "clear lines of authority and ownership for security matters." With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

Reliability Standard Audit Worksheet[1]

~~CIP-003-6~~CIP-003-7 – Cyber Security — Security Management Controls

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1	X	X	X	X	X				X			X	X		
R2	X	X	X	X	X				X			X	X		
R3	X	X	X	X	X				X			X	X		
R4	X	X	X	X	X				X			X	X		

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

[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. 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.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
~~P2.1~~			
~~P2.2~~			
~~P2.3~~			
~~P2.4~~			
~~P2.5~~			
~~P2.6~~			
R3			
R4			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

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

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

1.1.1. Personnel & training (CIP-004);

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

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

1.1.4. System security management (CIP-007);

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

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

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

1.1.8. Information protection (CIP-011); and

1.1.9. Declaring and responding to CIP Exceptional Circumstances.

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

1.2.1. Cyber security awareness;

1.2.2. Physical security controls;

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

1.2.4. Cyber Security Incident response

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

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to ~~CIP-003-6~~CIP-003-7, R1

This section to be completed by the Compliance Enforcement Authority

	For its high impact and medium impact BES Cyber Systems, if any, verify the Responsible Entity has documented one or more cyber security policies that collectively address the following topics: 1. Personnel and training (CIP-004); 2. Electronic Security Perimeters (CIP-005) including Interactive Remote Access; 3. Physical security of BES Cyber Systems (CIP-006); 4. System security management (CIP-007); 5. Incident reporting and response planning (CIP-008); 6. Recovery plans for BES Cyber Systems (CIP-009); 7. Configuration change management and vulnerability assessments (CIP-010); 8. Information protection (CIP-011); and 9. Declaring and responding to CIP Exceptional Circumstances.
	For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any, verify the Responsible Entity has documented one or more cyber security policies that collectively address the following topics: 1. Cyber security awareness; 2. Physical security controls; 3. Electronic access controls for Low Impact External Routable ~~Connectivity~~ Communication (LERC) and Dial-up Connectivity; and 4. Cyber Security Incident response.
	Verify each policy used to meet this Requirement has been reviewed at least once every 15 calendar months.
	Verify the CIP Senior Manager has approved each policy used to meet this Requirement at least once every 15 calendar months.
Note to Auditor: Per Attachment 1, "Responsible Entities with multiple-impact BES Cyber Systems ratings can utilize policies,	

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

Auditor Notes:

R2 Supporting Evidence and Documentation

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

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

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

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to ~~CIP-003-6~~CIP-003-7, R2

This section to be completed by the Compliance Enforcement Authority

	For each asset or group of assets containing low impact BES Cyber Systems, verify that the Responsible Entity has documented one or more cyber security plan(s), as specified in Attachment 1, for its low impact BES Cyber Systems that include: 1. Cyber security awareness; 2. physical security controls; 3. electronic access controls; and 4. Cyber Security Incident response
	For each asset or group of assets containing low impact BES Cyber Systems, verify that the Responsible

	Entity has reinforced cyber security awareness of its cyber security practices (which may include associated physical security practices) at least once every 15 calendar months.
	For each asset or group of assets containing low impact BES Cyber Systems, verify that the Responsible Entity has implemented physical access controls, based on need as determined by the Responsible Entity, to control physical access to: 1. The asset or the locations of the low impact BES Cyber Systems within the asset; and 2. ~~the Low Impact BES Cyber System Electronic Access Points (LEAPs)~~the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.
	For each asset or group of assets containing low impact BES Cyber Systems, does the Responsible Entity have any Low Impact External Routable ~~Connectivity~~ Communication (LERC)? • If yes, verify that the Responsible Entity implemented ~~a LEAP~~electronic access control(s) to permit only necessary ~~inbound and outbound bi-directional routable protocol~~electronic access to low impact BES Cyber System(s). • If no, verify that LERC does not exist.
	For each asset or group of assets containing low impact BES Cyber Systems, verify that the Responsible Entity has implemented authentication for all Dial-up Connectivity, if any, that provides access to low impact BES Cyber Systems, per Cyber Asset capability.
	For each asset or group of assets containing low impact BES Cyber Systems, verify that the Responsible Entity has one or more Cyber Security Incident response plan(s) that includes: 1. Identification, classification, and response to Cyber Security Incidents; 2. Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity ~~Sector~~ Information Sharing and Analysis Center (E~~S~~-ISAC), unless prohibited by law; 3. Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals; 4. Incident handling for Cyber Security Incidents; 5. Testing each Cyber Security Incident response plan at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and 6. Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.
	For each asset or group of assets containing low impact BES Cyber Systems, if the Responsible Entity responded to a Cyber Security Incident, verify the Responsible Entity implemented the Cyber Security Incident response plan.
	Verify the Responsible Entity tested each Cyber Security Incident response plan at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident.
	Verify the Responsible Entity updated each Cyber Security Incident response plan, if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable

	Cyber Security Incident.

Auditor Notes:

R3 Supporting Evidence and Documentation

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

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

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to ~~CIP-003-6~~CIP-003-7, R3

This section to be completed by the Compliance Enforcement Authority

	Verify the CIP Senior Manager has been identified by name.
	Verify that any changes made to the CIP Senior Manager were dated and documented within 30 calendar days of the change.
	Verify the CIP Senior Manager is 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.

Auditor Notes:

R4 Supporting Evidence and Documentation

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

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

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to ~~CIP-003-6~~CIP-003-7, R4

This section to be completed by the Compliance Enforcement Authority

	Verify that the Responsible Entity has documented a process to delegate authority, unless no delegations are used.
	Verify that all delegates have been identified by name or title.
	Verify that the delegation of authority includes the specific action delegated.
	Verify specific actions delegated by the CIP Senior Manager are allowed by the CIP Standards.
	Verify that the dates for all delegations have been recorded.

	Verify that the CIP Senior Manager approved all delegations.
	Verify that any changes made to delegations were dated and documented within 30 days of the change.
Note to Auditor: Delegations of the CIP Senior Manager's authority are permitted for the required approvals in CIP-002-5.1, Requirement R2 and CIP-007-6, Requirement R2, Part 2.4.	

Auditor Notes:

Additional Information:

Reliability Standard

The full text of ~~CIP-003-6~~CIP-003-7 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

See FERC Order 706
See FERC Order 791
See FERC Order 822

~~CIP-003-6~~CIP-003-7 - Attachment 1

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

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

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

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

Section 2. Physical Security Controls: Each Responsible Entity shall control physical access, based on need as determined by the Responsible Entity, to (1) the asset or the locations of the low impact BES Cyber Systems within the asset ~~and (2) the Low Impact BES Cyber System Electronic Access Points (LEAPs)~~, and (2) the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.

Section 3. Electronic Access Controls: Each Responsible Entity shall:

3.1 ~~For~~ Implement electronic access control(s) for LERC, if any, ~~implement a LEAP~~ to permit only necessary ~~inbound and outbound bi-directional routable protocol access;~~electronic access to low impact BES Cyber System(s). ~~and~~

3.2 Implement authentication for all Dial-up Connectivity, if any, that provides access to low impact BES Cyber Systems, per Cyber Asset capability.

Section 4. Cyber Security Incident Response: Each Responsible Entity shall have one or more Cyber Security Incident response plan(s), either by asset or group of assets, which shall include:

4.1 Identification, classification, and response to Cyber Security Incidents;

4.2 Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity ~~Sector~~ Information Sharing and Analysis Center (E~~S~~-ISAC), unless prohibited by law;

4.3 Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals;

4.4 Incident handling for Cyber Security Incidents;

4.5 Testing the Cyber Security Incident response plan(s) at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a

drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and

4.6 Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.

~~CIP-003-6~~CIP-003-7 - Attachment 2

Examples of Evidence for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Section 1 - Cyber Security Awareness: An example of evidence for Section 1 may include, but is not limited to, documentation that the reinforcement of cyber security practices occurred at least once every 15 calendar months. The evidence could be documentation through one or more of the following methods:

- Direct communications (for example, e-mails, memos, or computer-based training);
- Indirect communications (for example, posters, intranet, or brochures); or
- Management support and reinforcement (for example, presentations or meetings).

Section 2 - Physical Security Controls: Examples of evidence for Section 2 may include, but are not limited to:

- Documentation of the selected access control(s) (e.g., card key, locks, perimeter controls), monitoring controls (e.g., alarm systems, human observation), or other operational, procedural, or technical physical security controls that control physical access to both:
  a. The asset, if any, or the locations of the low impact BES Cyber Systems within the asset; and
  b. The Cyber Asset specified by the Responsible Entity that provides electronic access controls implemented for Section 3.1, if any~~, containing a LEAP~~.

Section 3 - Electronic Access Controls: Examples of evidence for Section 3 may include, but are not limited to:

1. ~~•~~Documentation, such as representative diagrams or lists of implemented electronic access controls (e.g., restricting IP addresses, ports, or services; authenticating users; air-gapping networks; terminating routable protocol sessions on a non-BES Cyber Asset; implementing unidirectional gateways) showing that ~~inbound and outbound connections~~ for ~~any LEAP(s) are~~ LERC at each asset or group of assets containing low impact BES Cyber Systems, is confined ~~to~~ only ~~those~~ to that access the Responsible Entity deems necessary ~~(e.g., by restricting IP addresses, ports, or services); and documentation~~; and

~~1.~~2. Documentation of authentication for Dial-up Connectivity (e.g., dial out only to a preprogrammed number to deliver data, dial-back modems, modems that must be remotely controlled by the control center or control room, or access control on the BES Cyber System).

Section 4 - Cyber Security Incident Response: An example of evidence for Section 4 may include, but is not limited to, dated documentation, such as policies, procedures, or process documents of one or more Cyber Security Incident response plan(s) developed either by asset or group of assets that include the following processes:

1. to identify, classify, and respond to Cyber Security Incidents; to determine whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and for notifying the Electricity ~~Sector~~ Information Sharing and Analysis Center (E~~S~~-ISAC);
2. to identify and document the roles and responsibilities for Cyber Security Incident response by groups or individuals (e.g., initiating, documenting, monitoring, reporting, etc.);
3. for incident handling of a Cyber Security Incident (e.g., containment, eradication, or recovery/incident resolution);
4. for testing the plan(s) along with the dated documentation that a test has been completed at least once every 36 calendar months; and
5. to update, as needed, Cyber Security Incident response plan(s) within 180 calendar days after completion of a test or actual Reportable Cyber Security Incident.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
DRAFT1v0	~~06/17/2014~~08/02/2016	~~Posted for Industry Comment~~CIP RSAW Development Team	New Document
~~DRAFT2v0~~	~~09/17/2014~~	~~CIP RSAW Development Team~~	~~Address comments received in response to DRAFT1v0.~~
~~DRAFT3v0~~	~~12/10/2014~~	~~CIP RSAW Development Team~~	~~Revise RSAW to address new standard language.~~ ~~Address comments received in response to DRAFT2v0.~~
~~DRAFT4v0~~	~~02/06/2015~~	~~CIP RSAW Development Team~~	~~Address comments from V5R SDT and address comments in response to DRAFT3v0.~~
~~DRAFT4v1~~	~~03/06/2015~~	~~CIP RSAW Development Team~~	~~Address comments from V5R SDT meeting on March 3-4, 2015.~~
~~FINALv1~~	~~05/08/2015~~	~~CIP RSAW Development Team~~	~~Address comments from final posting; review and address comments of V5R SDT.~~

New or Modified Term(s) Used in NERC Reliability Standards

Glossary Term(s):

System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations. ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

SOL Exceedance: An operating condition characterized by any of the following:

- Actual or pre-Contingency flow on a Facility is above the Normal Rating
- Calculated post-Contingency flow on a Facility is above the highest Emergency Rating
- Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs
- Actual or pre-Contingency bus voltage is outside normal System voltage limits
- Calculated post-Contingency bus voltage is outside the emergency system voltage limits
- Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs
- Operating parameters indicate the next Contingency could result in instability.

DRAFT

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon

2. **Number:** FAC-011-4

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall:

3.1. Require that System voltage limits are not outside of the Facility voltage ratings;

3.2. Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements;

3.3. Require that System voltage limits are above UVLS relay settings;

3.4. Identify the lowest allowable System voltage limit;

3.5. Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and,

3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limitations to be used in operations. The method shall:

4.1. Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies:

4.2.1. Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault:

- generator;
- Transmission circuit;
- transformer;
- shunt device;
- single pole of a direct current line.

4.2.2. Loss of any multiple Contingencies identified in Requirement R5.

4.3. Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch;

4.4. Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8;

4.5. Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and,

4.6. Specify how stability limitations will be established when there is an impact to more than one TOP in its Reliability Coordinator Area.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.

R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including:

6.1. Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation;

6.2. Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation;

6.3. Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and,

6.4. Unacceptable impacts on neighboring Reliability Coordinator Areas within an Interconnection.

R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.

R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address:

8.1. Thresholds for initiating evaluation of potential impacts;

8.2. A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and,

8.3. A review of the operating state experience for the purpose of determining whether an IROL should be established.

R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to:

9.1. Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;

9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and,

9.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

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A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-3

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

   4.1.3. Planning Coordinator

   4.1.4. Transmission Planner

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.

R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.

R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.

R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area.

4.1. The Reliability Coordinators shall provide any updates to the SOL values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.

R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area:

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5.1. Identification of the Facilities that are critical to the derivation of the IROL;

5.2. The value of the IROL and its associated IROL T_V;

5.3. The associated Contingency(ies); and,

5.4. The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).

R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area:

6.1. Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.

R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include:

8.1. The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation);

8.2. The Contingencies which result in the instability;

8.3. Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and,

8.4. Any Corrective Action Plan associated with the instability.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Proposed Revisions

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** (SOL). The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Lacey Ourso, Standards Developer by email or phone at 404.446.2581.

Background Information regarding Project 2015-09 Establish and Communicate System Operating Limits

The Facilities Design, Connections, and Maintenance (FAC) Reliability Standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) used in the reliable operation of the Bulk Electric System (BES). The purpose of Project 2015-09 – Establish and Communicate System Operating Limits is to revise these requirements. Revisions are necessary to eliminate overlap with approved Transmission Planning (TPL) requirements,[1] enhance consistency with Transmission Operations (TOP)[2] and Interconnection Reliability Operations (IRO)[3] standards, and address other concerns in the existing FAC standards regarding the determination and communication of SOLs and IROLs. As outlined in the Standards Authorization Request (SAR), the scope of the standards development project includes development of new or revised requirements and/or NERC Glossary definitions to provide clarity and consistency for establishing SOLs and IROLs, and to address potential reliability issues resulting from application of the current NERC Glossary definitions for SOL and IROL.[4]

High-level Overview of Proposed Revisions to FAC Reliability Standards

In developing revisions to the FAC Reliability Standards and definitions related to SOL and IROL, the standard drafting team (SDT) has focused on alignment with how SOLs and IROLs are treated in the approved TOP and IRO Reliability Standards (enforceable beginning April 1, 2017). The SDT believes this shift is critical to align the approach for how the System is actually operated as a result of the wholesale

[1] *See*, TPL-001-4
[2] *See*, TOP-001-3, TOP-002-4, TOP-003-3
[3] See, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1
[4] The SAR was sponsored and submitted by the Project 2015-03 -Periodic Review of System Operating Limit Standards periodic review team (PRT).

revisions to the TOP and IRO Reliability Standards and reflects the manner in which operations are currently conducted. Below is a detailed explanation of how the proposed revisions complement the TOP/IRO revisions. The proposed changes to the FAC standards support a more reliable, dynamic approach to operating within actual limits that exist on the system, as opposed to reliance on "operating limits" that were set well in advance.

Overview of How Proposed Revisions Align with Revised TOP and IRO Reliability Standards

The revisions proposed to the FAC standards were designed to work together with the approved TOP and IRO Reliability Standards. The combination of the proposed revisions to the FAC standards and the TOP and IRO Reliability Standards, including the defined terms contained in those standards (Operational Planning Analysis (OPA)[5], Real-time Assessment (RTA)[6], and Operating Plans) when executed together will result in maintaining reliable BES performance. Thus, it is imperative that your review of the proposed revisions to the FAC standards is conducted with a full understanding of how these standards will work together with the approved TOP and IRO Reliability Standards. The proposed FAC revisions standing alone will not provide a complete picture of how different functional entities will work together to establish the appropriate operational limits, and then actually operate to them.

Under the approved TOP and IRO Reliability Standards:

- TOP-002-4 Requirement R1 requires the TOP to have an OPA that will allow it to assess whether its planned operations for the next day will exceed any of its SOLs.
- TOP-002-4 Requirement R2 requires that the TOP have an Operating Plan to address potential "SOL exceedances" identified as a result of its OPA.
- TOP-001-3 Requirement R13 requires that the TOP perform a RTA at least once every 30 minutes.

[5] NERC Glossary defines Operational Planning Analysis (OPA) as, "An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" [NERC Glossary as of June 24, 2016]

[6] NERC Glossary defines Real-time Assessment (RTA) as, "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.) [NERC Glossary as of June 24, 2016]

- TOP-001-3 Requirement R14 requires that the TOP initiate its Operating Plan to mitigate an "SOL exceedance" identified as part of its Real-time monitoring or RTA.

For more information on the TOP/IRO revisions, please visit the Project 2014-03 Revisions to TOP/IRO Reliability Standards project page.

Overview of Proposed Revisions to FAC-011-3, FAC-014-2 and Defined Terms SOL and SOL Exceedance

As outlined in greater detail below, the SDT is proposing to revise the existing definition of SOL and create a new NERC Glossary definition for "SOL Exceedance." The new definitions support the conceptual distinction between operating practices and the SOL itself. The SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity operates to those SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by the entity. The revised definition of SOL and new definition of "SOL Exceedance" will work together with the future-enforceable TOP and IRO Reliability Standards, including the definitions of OPA, RTA and Operating Practices as follows:

- The TOP is required to have an OPA to assess whether its planned operations for the next day will exceed any of its SOLs (*see*, TOP-002-4, Requirement R1). If the OPA identifies potential SOL exceedances, the TOP is required to have an Operating Plan to address those potential SOL exceedances (*see*, TOP-002-4, Requirement R2).
- Additionally, the TOP is required to perform a RTA at least once every 30 minutes (*see*, TOP-001-3 Requirement R13). If the TOP identifies that an SOL is being exceeded in Real-time operations, the TOP will implement the mitigating strategies identified in its Operating Plan (*see*, TOP-001-3 Requirement R14).
- In other words, an "SOL Exceedance" is simply unacceptable system performance that must be mitigated in accordance with the action plan the TOP has laid out in its Operating Plan.
- A potential SOL Exceedance may be identified by an OPA, or an actual SOL Exceedance may be identified by an RTA.
- The Operating Plan can include specific Operating Procedures or more general Operating Processes. The TOP Operating Plans include both pre- and post- Contingency mitigation plans and strategies. The pre-Contingency strategies are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans and strategies are actions that the TOP will implement after the Contingency occurs to bring the system back within limits.
- The Operating Plans contain adequate details regarding the appropriate timelines to escalate the level of mitigation to ensure BES performance is maintained as required by the RC SOL Methodology.

The proposed definition of SOL Exceedance (described in further detail below) provides clarity regarding what is deemed to be "unacceptable system performance." When the conditions identified in the definition of SOL Exceedance occur, the TOP must be prepared

to implement its action plan outlined in its Operating Plan to mitigate that particular condition and return the system back within acceptable limits.

The SDT believes that the proposed definitions and revisions to the FAC standards will eliminate confusion between the operating practices used by the TOP and the actual limits themselves. The revisions provide clarity regarding (1) what the limits are, (2) what it means to exceed them, and (3) how an "SOL Exceedance" should be addressed by the TOP in operations planning (TOP-002-4 Requirement R2) and Real-time operations (TOP-001-3 Requirement R14).

Purpose of 30-day Informal Comment Period

As outlined above, the scope of Project 2015-09 includes revision of the requirements for determining and communicating SOLs and IROLs used in the reliable planning and operation of the BES. This informal 30-day posting does not encompass the entire scope of work that the SDT will undertake for the project. Rather, this is only a piece of the complete work. However, the SDT believes it to be the most critical area. The direction taken with regard to these standards set the foundation for building a proper SOL methodology to ensure that SOLs are established and communicated in a manner that will later ensure reliable BES operation when carried out in operations.

Reliability Standards and definitions that **are included** (as part of this limited, informal posting):

- FAC-011-3 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 – Establish and Communicate System Operating Limits
- Revisions to definition of System Operating Limit (SOL)
- New definition of SOL Exceedance

Reliability Standards and definitions that **are NOT included** (as part of this limited, informal posting):

- FAC-010-3 – System Operating Limits Methodology for the Planning Horizon
- Revisions to definition of Interconnection Reliability Operating Limit (IROL)
- Necessary revisions to existing Reliability Standards to incorporate concepts included in new defined term "SOL Exceedance" (*i.e.,* TOP-002-4 – capitalize SOL Exceedance to incorporate usage of defined term).

Although this is only an informal posting, the SDT underscores the importance of this posting. The SDT believes that the revisions proposed represent a significant improvement in how the industry works together to ensure reliability by establishing SOLs and operating to them in a manner that is reflective of the changing technology, and dynamic manner where entities have the ability to assess pre- and post-

Contingency performance in Real-time based on actual operating conditions. For these reasons, the SDT requests that commenters please take the time to review the background materials from the Project 2015-09 SOL Technical Conference which outline all of the various issues that were considered by the team, and discussed in an open forum with industry members. The SDT believes that we have captured the essence of the direction that the industry would like to take, but this is the opportunity for the team to continue to improve on proposed revisions by obtaining early feedback. The SDT looks forward to hearing and understanding your perspective for each of the very specific issues and associated questions raised below. In order for the SDT to thoroughly understand and incorporate your feedback into the future standard development, please do not simply provide yes or no responses. Please provide us with your perspective. Give us as much detail as you can. If you disagree with the SDT's direction, please provide an alternative approach that you believe will be superior to the one that the SDT proposed.

Proposed Revisions, Background Information and Questions

A. Definitions

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations.	The current definition of SOL (and the related FAC standards) presume an operating paradigm whereby a study or analysis is performed ahead of time to establish an SOL; the SOL is then communicated to operators; and the operators are given an operating plan to operate below the SOL with the presumption that doing so will result in acceptable pre- and post-Contingency system performance in Real-time operations. However, due to changes in the TOP and IRO Reliability Standards, along with advancements in technology from the time that the FAC standards were originally drafted, this is not reflective of how the system is actually operated. Today, entities continuously assess system performance and identify potential events in Real-time, based on *actual* operating conditions. The proposed revisions to the SOL definition, coupled with the proposed new definition of SOL Exceedance (see below) and the revisions to the FAC standards will support the concept that the SOL is the actual operating parameter; and eliminate confusion between "what the limits are" verses "how the system should be operated given the limits."	Existing definition of SOL: "The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post-Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability)

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	Given this shift, there is no need for the existing SOL definition language that includes concepts of "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post-Contingency." These concepts are covered in the future-enforceable TOP and IRO Reliability Standards (including the defined terms contained therein: OPA, RTA, and Operating Plans), along with the proposed revisions to the FAC standards. As a result of the proposed revisions, the Facility Ratings, System voltage limits, and stability limitations are SOLs, all of the time, regardless of which one is "the most limiting." Also, as detailed below, the definition of "SOL Exceedance" will complement the revised definition of SOL by specifically identifying operating conditions that are deemed unacceptable, and require action by the TOP to mitigate. The proposed revisions use the term "stability limitation" rather than "transient stability limit," "voltage stability limit" or the Glossary term "Stability Limit." The intent of the SDT is that "stability limitation" is intentionally broad and can be used to encompass a number of different types of stability-related limitations or phenomenon, including, but not limited to, weighted short-circuit ratio (WSCR), sub-synchronous resonance (SSR), phase angle limitations, fault-interrupting capability of breakers, transient voltage limitations on equipment, and geomagnetic-induced currents on equipment. The Glossary term "Stability Limits" is not appropriate because it is limited to the maximum power flow value; this is too restrictive and not technology-neutral, as tools allow entities	• system voltage limits (applicable pre- and post-Contingency voltage limits)"

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	to monitor and control parameters other than maximum power flow values in order to demonstrate reliable stability performance. For more information regarding the proposed revisions to the SOL definition (and the definition of SOL Exceedance), please reference the Project 2014-03 – TOP and IRO Reliability Standards white paper entitled, "System Operating Limit Definition and Exceedance Clarification."	

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
SOL Exceedance: An operating condition characterized by any of the following: • Actual or pre-Contingency flow on a Facility is above the Normal Rating; • Calculated post-Contingency flow on a Facility is above the highest Emergency Rating;	As explained above, under the proposed revisions, the SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity remains within those SOLs will vary depending upon the particular Operating Plan of the entity. When the operating conditions listed in the definition of SOL Exceedance are identified – through an OPA or RTA – the TOP will take the actions outlined in its Operating Plan to mitigate the condition. The SDT did not include specific timing requirements for each condition listed in the definition, because the appropriate timing for operator response can vary depending upon the particular facts and	**Mapping to existing FAC standards or definitions under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- Identifies performance requirements that RC SOL Methodology shall include. If the definition of SOL Exceedance is pursued by the SDT, the definition would be incorporated into existing standards that currently rely on the concept of an

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
• Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs; • Actual or pre-Contingency bus voltage is outside normal System voltage limits; • Calculated post-Contingency bus voltage is outside the emergency system voltage limits; • Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs; or, • Operating parameters indicate the next Contingency could result in instability.	circumstances. However, it is expected (and required) that the TOP Operating Plan specifically identify the allowable response time, along with the specific actions to be taken by the operator, in mitigating the condition. The bulleted items carry forward the types of limitations that are identified in the current definition of SOL, and incorporate the concepts of acceptable/unacceptable system performance, as currently contained in FAC-011-3 Requirement R2. For bullet item 3: This operating condition exists when the calculated post-Contingency flow falls below the highest Emergency Rating; however, the flow remains at a level where there is not sufficient time to reduce the flow to an acceptable level after the Contingency occurs. In this operating condition, the operator would be required to take pre-Contingency action, and could not rely on a post-Contingency mitigation plan. Because pre-Contingency action is required, the condition is deemed to be an "SOL Exceedance." For bullet items 4 and 5: Normal and emergency System voltage limits must respect the voltage limitations specified in the TO or GO Facility Ratings methodology (pursuant to FAC-008-3). Normal voltage limits are typically applicable for the pre-Contingency state, while emergency voltage limits are applicable for the post-Contingency state. "SOL Exceedance" with respect to these voltage	"SOL exceedance." The intent is not to change the meaning of the existing standards, rather the SDT believes that the proposed definition captures the existing meaning, but simply provides greater clarity through listing the specific types of conditions in the "SOL Exceedance" definition. In concert with proposing the new "SOL Exceedance" definition, the SDT would propose revisions (only as necessary) to existing standards to incorporate the newly defined Glossary term. Below are a few examples, but are not intended to represent a comprehensive or complete listing: • TOP-002-4 Requirement R1 - Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will result in an SOL Exceedance of its System Operating Limits (SOLs).

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
	limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments recognize whether auto-reactive devices are sufficient for maintaining voltage within acceptable limits pre- or post-Contingency.	• TOP-002-4 Requirement R2 - Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) Exceedance(s) identified as a result of its Operational Planning Analysis as required in Requirement R1. • TOP-001-3 Requirement R14 - Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL Exceedance identified as part of its Real-time monitoring or Real-time Assessment.

B. Proposed Revisions to FAC-011-3

Proposed Reliability Standard: FAC-011-4, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	As outlined above, the SDT has incorporated the concepts contained in the existing FAC-011-3 Requirement R1 into the proposed revisions to the definitions of SOL and SOL Exceedance, along with the proposed revisions to FAC-011 and FAC-14. The existing Parts 1.1 through 1.3 are incorporated into the proposed new requirements, as detailed below.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – Sentence 1.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and	Under FAC-008-3, Facility Ratings are established by Facility owners (TOs and GOs) consistent with the owner's methodology. These Facility Ratings are communicated to the RCs and TOPs. RCs and TOPs incorporate these ratings into their tools and processes and use the ratings in establishing their SOLs. Because TOs and GOs are not required to use any sort of continent-wide methodology for establishing the Facility	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 Requirements R1, R2 and R3– GOs and TOs are required to have a methodology for developing Facility Ratings. • FAC-008-3 Requirement R6– GOs and TOs shall establish Facility Ratings consistent with its methodology.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
the Transmission Operators in its Reliability Coordinator Area.	Ratings, it is possible for owners to use varying/different methodologies. This can create problems in establishing the appropriate SOL because the variations in Facility Rating methodologies may result in different or inconsistent types of Facility Ratings used in operations. If the RCs and TOPs are using different sets of Facility Ratings in conducting their respective outage coordination studies, OPAs, and RTAs, this may create a potential risk to reliability. The intent of Requirement R2 is for the RC SOL Methodology to identify the method that its TOPs will use in determining which of the Facility Ratings provided by the owner (under FAC-008-3) are appropriate for use in establishing SOLs for use in operations. As outlined above, under the revised definition of SOL, the Facility Ratings will be the SOL. The second sentence of Requirement R2 is intended to ensure that the RC and the TOP are using the same Facility Ratings, which will eliminate the risk identified above.	• FAC-008-3 Requirements R7 and R8– must provide their Facility Ratings to the RC, TOP and other functional entities. **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- RC SOL Methodology shall include requirement that SOLs provide BES performance, and following certain prescribed conditions/states, remain within their Facility Ratings.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall: **3.1.** Require that System voltage limits are not outside of the Facility voltage ratings; **3.2.** Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements; **3.3.** Require that System voltage limits are above UVLS relay settings; **3.4.** Identify the lowest allowable System voltage limit; **3.5.** Address the use of common System voltage limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area; and,	There is no Reliability Standard that specifically requires establishment and communication of System voltage limits; however, System voltage limits are used in the definition of SOL and are an important aspect of reliable operations. The SDT believes it is important for the Reliability Standards to assign responsibility for the establishment and communication of System voltage limits. Like Facility Ratings, System voltage limits should be consistent between TOPs and RCs throughout all operations processes. The proposed Requirement R3 will result in the RC SOL Methodology requiring the TOP to determine System voltage limits for use in operations, consistent with the RC methodology.	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 – Requires Facility Owner to establish Facility Ratings, which includes voltage ratings.[7] • VAR-001-4 Requirement R1 – The TOP specifies the system voltage schedule (which is either a range or a target value associated with a tolerance band) as part of its plan to operate within SOLs (and IROLs). **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2) - RC SOL Methodology shall include requirement that SOLs provide BES performance with regard to certain prescribed conditions (pre-Contingency state, following certain identified single-

[7] Definition of Facility Ratings: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.		Contingencies) and remain within their thermal and voltage limits. [Proposed definitions of SOL and SOL Exceedance and Requirement R3 carry this forward.] • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. [Proposed Part 3.1 carries this forward.] • Parts 3.2-3.6 were not clearly identified in the previous FAC standards; these are "new" requirements added by the SDT to provide clarity regarding steady-state system voltage limits.

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall include in its SOL Methodology the method for	As detailed above, the existing definition of SOL provides that the SOL is "based upon" certain criteria, including transient stability ratings. The proposed	**Background regarding existing standards *not* under revision by SDT:**

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
determining the stability limitations to be used in operations. The method shall: **4.1.** Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following: **4.1.1.** steady-state voltage stability; **4.1.2.** transient voltage response; **4.1.3.** angular stability; and, **4.1.4.** System damping. **4.2.** Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies: **4.2.1.** Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator;	revisions to the SOL definition make clear that the SOLs "are" the reliability limits, which include stability limitations. Additionally, under the current standards, there are no set continent-wide stability limitations criteria for use in determining SOLs. Under existing FAC-011-3 Requirement R2, the RC has flexibility with regard to establishing stability limitations; provided the system performance requirements in the standard are met. While the existing language in Requirement R2 (and portions of Requirement R3) do provide some "continent-wide" uniformity, the requirements do not provide sufficient clarity regarding the distinction between establishing stability limitations and acceptable system performance requirements/response. The proposed revisions continue to allow the RC to have flexibility in its SOL Methodology for developing stability limitations. This ensures the RC is able to appropriately tailor the methodology to meet the particular needs of its system, since a "one size fits all" approach is not appropriate for stability limitations. However, the proposed requirement does set a number of minimum	• IRO-005-3.1a, Requirement R1 (Parts 1.2 and 1.3) – Each RC should monitor its RC Area parameters, including pre and post contingent element stability conditions. • IRO-008-2, Requirement R1 – Each RC shall perform an OPA that will assess whether next day planned operations will exceed SOLs or IROLs within its Wide-area. • MOD-001-2, Requirement R1 (Part 1.1) – Each TOP that calculates TFC or TTC shall have a written methodology that describes how those values are calculated, including the pre- and post-Contingency limitations for transient and voltage stability limits and other SOLs. **Mapping to existing FAC standards under revision:** • FAC-014-2, Requirement R6 (Parts 6.1 and 6.2) – Planning Authority shall provide multiple contingencies causing stability limits, and the limits, to the

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
• Transmission circuit; • transformer; • shunt device; • single pole of a direct current line. **4.2.2.** Loss of any multiple Contingencies identified in Requirement R5. **4.3.** Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch; **4.4.** Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8; **4.5.** Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and, **4.6.** Specify how stability limitations will be established when there is an impact to	required attributes (specific to stability limitations) that must be contained within the RC SOL Methodology. The proposed approach by the SDT is for the RC SOL Methodology to continue to set the method for how stability limitations for its RC Area must be established. Under proposed Requirement R4, the RC SOL Methodology must: Part 4.1 - Specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied. Part 4.2 - Meet the performance criteria for certain identified Contingencies (listed in the standard). Part 4.3 - Describe how instability risks are identified. The SDT changed the existing language of "anticipated" to "realistic." (See, FAC-011-3 Part 3.6) The SDT believes "anticipated" could be broadly interpreted to mean anticipated by the planners (in planning horizon), instead of what is realistically anticipated by the operators in the operations time horizon. Part 4.4 – Incorporates concepts from the existing FAC-011-3 Part 3.3, and requires the RC to consider the	Reliability Coordinator, or note to the RC if there are none. *[Maps to proposed Part 4.4]* • FAC-011-3 Requirement R2 (Part 2.1) - *[Maps to proposed Part 4.1, with new requirement providing specific types of criteria that must be considered.]* • FAC-011-3 Requirement R2 (Part 2.2) - *[Maps to proposed Part 4.2]* • FAC-011-3 Requirement R2 (Part 3.6) - *[Maps to proposed Part 4.3]* • FAC-011-3 Requirement R3 (Parts 3.1 and 3.5) – *[Maps to proposed Part 4.5]*

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one TOP in its Reliability Coordinator Area.	stability limitations provided by the Planning Coordinator. Part 4.5 – This language combines some components of existing FAC-011-3 Parts 3.1, 4.3, and 3.5, but removes the blanket requirement for the study to include the entire RC Area. The revised language allows the RC to have flexibility to determine the appropriate study model, and required supporting details. Part 4.6 – The SDT believes that this Part will improve reliability by requiring the RC SOL Methodology to specify the appropriate manner to develop stability limitations, when those limitations impact more than one TOP in its RC Area. A companion requirement is FAC-014-3 Requirement R3, which requires the RC to determine the stability limitations when there is an impact to more than one TOP in its RC Area. (*See*, the proposed FAC-014-3 Requirement R3 for further explanation).	

Proposed Reliability Standard: FAC-011-4, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.	Currently effective Reliability Standard TOP-004-2 Requirement R3 requires the TOP operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its RC. This requirement was retired by the TOP/IRO project because it was addressed by the new TOP-001-3 Requirements R12 and R14 (which are not limited by single or multiple contingencies) in combination with existing FAC-011-3 Part 3.3 and FAC-014-2 Requirement R6 (which work collectively to establish how multiple Contingencies are considered in IROLs and SOLs). The proposed Requirement R5 maintains the existing approach that the RC SOL Methodology shall specify the multiple Contingencies for use in establishing stability limitations and IROLs. Further, it improves upon the existing requirement by allowing the RC SOL Methodology to identify multiple Contingencies beyond those identified by the planners.	**Background regarding existing standards *not* under revision by SDT:** • TOP-001-3 Requirements R12 and R14 **Mapping to existing FAC standards under revision:** • FAC-011-3 Part 3.3 • FAC-014-2 Requirement R6

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including: **6.1.** Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation; **6.2.** Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation; **6.3.** Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and, **6.4.** Unacceptable impacts on neighboring Reliability	Regional differences exist in the criteria for determining which subset of SOLs are IROLs. The SDT discussed the regional differences among the various RC Areas, and several similarities emerged, including: (1) loss of load criteria, (2) loss of generation criteria, (3) non-localized or uncontained instability, and (4) impact on neighboring RC Area. The SDT evaluated the potential positive and negative impacts of creating continent-wide requirements, and determined that establishing minimum criteria that must be considered as part of the RC Methodology would benefit reliability; while continuing to allow necessary flexibility. The proposed language provides greater uniformity by identifying the criteria to be considered by the RC in establishing IROLs. The criteria must describe, at a minimum, the severity and extent of what is/not allowable with regarding to: (1) loss of load, (2) quality of supply loss, (3) thresholds for inter-area oscillations, and (4) impacts on neighboring RC Areas within its Interconnection. This minimum IROL criteria will provide for greater continent-wide consistency as it ensures all RCs consider and identify what is allowable for each criteria. The SDT believes while this does change the current state – where no mandatory minimum criteria exist- it still allows for the RC to have the necessary flexibility to design its IROL	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – RC SOL Methodology must include a description of how to identify the subset of SOLs that qualify as IROLs. • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
Coordinator Areas within an Interconnection.	methodology so that it can meet the reliability issues present in, and possibly unique to, its RC Area.	

Proposed Reliability Standard: FAC-011-4, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.	For the most part, the substance of this requirement is not changed from the existing standard; it was previously contained in a part (*i.e.,* FAC-011-3 Part 3.7) and is now a stand-alone requirement. The only change is that the 30 minute time-period is specifically identified, whereas in the previous requirement only stated T_v.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address: **8.1.** Thresholds for initiating evaluation of potential impacts; **8.2.** A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and, **8.3.** A review of the operating state experience for the purpose of determining whether an IROL should be established.	In Order No. 817, FERC noted that, "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability." The SDT believes that in certain circumstances, such as in response to forced outages or similar unforeseen events, Real-time operating conditions can occur such that a RTA identifies an operating state where the next Contingency could result in instability, uncontrolled separation or Cascading outages. When this operating condition occurs in Real-time, it is clear that System Operator(s) are expected to take urgent action to mitigate the N-1 insecure operating state. What is unclear, however, is whether this operating condition constitutes some sort of an "IROL exceedance" or mandates that other IROL-related Reliability Standards should be applied. The proposed requirement requires the RC SOL Methodology to prescribe a method for how to address the above-described Real-time operating state. This will allow for consistency by System Operators within an RC Area in responding to the Real-time operating state when tools or analysis indicate abnormal post-Contingency conditions (*e.g.*, unsolved Contingencies, high post-Contingency overloads). While the requirement treats the operating state similar to, and equally important to, what prepared response must be	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_V.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	in place for resolving an IROL-type issue, the requirement does not focus on formally establishing the limit, but instead allowing the System Operator to act with urgency to address the temporary operating state at hand. Also Part 8.3 requires the RC Methodology prescribe an after-the-fact review of the operating state experience for the purpose of determining whether an IROL should be established in accordance with the RC SOL Methodology.	

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to: **9.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;	For the most part, the substance of this requirement is not changed from the existing standard. A clarification was added to Part 9.1 that RCs should issue its SOL Methodology, and any associated changes, to the other RCs *within* its Interconnection.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R4 – Requires the RC to issue its SOL Methodology, and any changes to the methodology, to its adjacent RCs and any RCs indicating a reliability-related need; to each PC and TP that models portions of its

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and, **9.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.		RC Area; and, each TOP that operates in its RC Area.

C. Proposed Revisions to FAC-014-3

Proposed Reliability Standard: FAC-014-3, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.	The current FAC-014-2 Requirement R1 requires that the RC ensure SOLs and IROLs are established pursuant to its SOL Methodology. This creates a situation where the RC is responsible for "ensuring" actions out of its control. The proposed revisions do not change the intent of the standard –that the RC develop the SOL Methodology for establishing SOLs in its RC Area, and the TOP following the RC SOL Methodology in establishing those SOLs. Accordingly, the proposed Requirement R2 requires that the TOP establish SOLs as required by the RC SOL Methodology. The SDT believes this clarifies the appropriate responsibilities of the respective functional entities, while not creating ambiguity in the requirements in requiring the RC to do something that the TOP is, in all actuality, required to do. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R2		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.	The SDT has removed language from the existing FAC-014-3 Requirement R2 that states the TOP, "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the RC will issue a "Directive," or that TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and these SOLs must be established in accordance with (*i.e.*, pursuant to the "direction") identified in the RC's SOL Methodology.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts	The proposed approach by the SDT is that the RC SOL Methodology will set the method for how all stability limitations for its RC Area must be established (see, proposed	**Mapping to existing FAC standards under revision:**

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.	FAC-011-4 Requirement R4). The RC SOL Methodology must, among other things, specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied (see, proposed FAC-011-4 Part 4.1); meet the performance criteria for certain identified Contingencies listed in the standard (see, proposed FAC-011-4 Part 4.2); and describe how instability risks are identified (see, proposed FAC-011-4 Part 4.3). The TOP is required to establish stability limitation SOLs in accordance with everything outlined in the RC SOL Methodology. However, in addition to what is outlined above, the SDT believes that to the extent there are stability limitations that may impact more than one TOP in its RC Area, the RC should be responsible for determining these stability limitations (in accordance with its RC SOL Methodology – see, proposed FAC-011-4 Part 4.6). The purpose of providing a separate requirement for the RC to address this specific type of stability limitation is to provide clarity that there may be a stability limitation that is not appropriately labeled an "IROL," and thus, would not be covered by proposed Requirement R1. It is the position of the SDT that not all stability limitations are automatically "IROLs." For example, there may be instances of local, contained instability that are not appropriately designated	• N/A: This proposed requirement addresses what the SDT believes to be a gap in the existing requirements.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	an "IROL," because labeling it as an IROL may require the TOP to take actions such as pre-Contingency load shedding, that is not warranted, and could actually cause a bigger reliability impact. However, when the stability limitation impacts more than one TOP, the SDT believes the RC should have primary responsibility for establishing that SOL.	

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area. **4.1.** The Reliability Coordinators shall provide any updates to the SOL	The proposed Requirement R4 maintains the part of existing FAC-014-3 Requirement R5 which requires the TC to send the SOLs for its RC Area to adjacent RCs. The SDT has created a new/separate requirement related to communicating established IROLs (see proposed FAC-014-4 Requirement R5). The SDT added Part 4.1 to require the RC to provide updates to the SOLs to the impacted TOPs. It is expected that the RC and TOPs will establish a mutually agreeable means (pursuant to IRO-010-2 and TOP-003-3) for exchanging dynamically determined Facility Ratings or stability limitations.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.		

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area: **5.1.** Identification of the Facilities that are critical to the derivation of the IROL.	See above explanation. This requirement was previously combined with the requirement to provide updates to both SOLs and IROLs (existing FAC-014-3 Requirement R5). The SDT separated these into two requirements – one for SOL and one for IROL – so that greater detail could be provided regarding the type of IROL-information that must be communicated by the RC.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
5.2. The value of the IROL and its associated IROL T_V. **5.3.** The associated Contingency(ies). **5.4.** The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).		

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area: **6.1.** Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.	In FERC Order No. 777, FERC directed NERC to develop a means to assure that IROLs are communicated to transmission owners (*see*, P6 and P41). The purpose of this proposed requirement is to address the concerns raised by FERC in Order No. 777. The RC is required to provide the IROL information identified in Part 6.1 to Transmission Owners and Generator Owners in its RC Area. The SDT included Generator Owners because it believes that GOs, in addition to TOs, need to receive information relating to facilities that are critical to the derivation of the IROL. The SDT did not combine this with proposed Requirement R5 because the team believes that the owners only need IROL information related to their facilities that are critical to the	**Mapping to existing FAC standards under revision:** • N/A: This proposed requirement is intended to address the issues raised in FERC Order No. 777.

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
	derivation of the IROL. However, the owners do not need the information identified in proposed Parts 5.2 through Part 5.4, and further, this information may contain sensitive operator information not appropriate for open-ended sharing.	

Proposed Reliability Standard: FAC-014-3, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	The SDT did not make substantive changes to this requirement; however, the requirement previously existed as a "part" of a requirement and it is now a stand-alone requirement.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Part 5.2 – Requires the TOP to provide its SOLs to the RC and Transmission Service Providers in its portion of the RC Area.

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include: **8.1.** The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation); **8.2.** The Contingencies which result in the instability; **8.3.** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss that was employed (or invoked) to address the instability; and, **8.4.** Any Corrective Action Plan associated with the instability.	Under proposed FAC-011-4 Part 4.4, the RC SOL Methodology must consider the stability limitations provided by the Planning Coordinator. Also, proposed FAC-014-3 Requirements R2 and R3, the applicable entities are required to establish stability limitations (if any) in accordance with the RC SOL Methodology. This requirement is intended to complement proposed FAC-011-4 Part 4.4 by ensuring that the planning entities provide the results of their stability analysis, including a list of those contingencies that are expected to produce the more severe System impacts, to the affected RC and TOP. This information may be relevant to the operating conditions for which the RC and TOP are determining SOLs. Further, FAC-013-2 requires that the PC have a methodology and annual assessment that identifies the weaknesses and limiting Facilities that could limit the ability of the Transmission System to reliably transfer energy. The results of the assessment, including the methodology used in the analysis, may contain information that may be relevant to the RC and TOP analysis for determining SOLs (and IROLs).	**Background regarding existing standards *not* under revision by SDT:** • TPL-001-4 • FAC-013-2 **Mapping to existing FAC standards under revision:** • FAC -011-3 Part 3.3 • FAC -014-2 Requirement R6

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Revisions to Reliability Functional Model

Functional Model Advisory Group

Background Information

Background regarding the Reliability Functional Model and Reliability Functional Model Technical Document

The Reliability Functional Model (FM) is a guideline that identifies the functions that must be performed to ensure that the Bulk Power System (BPS) is planned and operated in a reliable manner. The FM describes, in general terms, the functions that must be performed to ensure reliability, the specific tasks that are necessary to perform each function, and the relationships between functional entities that perform the various tasks. In its capacity of a guideline, the FM serves to provide a framework for NERC Reliability Standards as they are developed through the standard development process. The FM is independent of any particular organizational or market structure. The focus of the FM is solely on identification of reliability-related functions and the associated tasks and relationships. The FM is **not** a "standard" and does not have compliance effects. If there is a conflict between the FM and Reliability Standards, the Reliability Standards always take precedence. Also, the FM is **not** intended to identify the entities responsible for NERC registration. The NERC registration process is undertaken by NERC (and the Regional Entities) pursuant to authority from FERC, ultimately derived from the Federal Power Act. The FM has no authority, ability, or intent to impact or influence the NERC Registration process. The Reliability Functional Model Technical Document (FMTD) is a companion document to the FM. It serves to elaborate on the manner in which the various functional entities carry out their functions and perform their tasks.

Background regarding the Functional Model Advisory Group

The purpose of the Functional Model Advisory Group (FMAG), as outlined in the FMAG Scope document, is to (1) maintain the FM and FMTD to ensure the model correctly reflects the industry today, and (2) evaluate and incorporate new and emergent reliability-related tasks. The FMAG reports to the Standards Committee (SC), and works with the Planning Committee (PC), Operating Committee (OC), and Critical Infrastructure Protection Committee (CIPC) to obtain consensus regarding any proposed changes to the FM and FMTD. All proposed changes to the FM must be posted for industry comment, obtain consensus agreement from the PC, OC, and CIPC, and, ultimately, approval by the SC.

Overview of the 2016 FMAG project

In December 2015, the FMAG began a comprehensive review and assessment of the FM and FMTD to determine if it correctly reflects the industry today and whether there was a need to incorporate any new or emerging reliability-related tasks. As a result of the review, the FMAG identified many areas in need of revision. Below is a general summary of the type and nature of the revisions proposed by the FMAG.

General Overview of Proposed Revisions

1. Incorporated defined terms from the NERC Glossary of Terms: A large majority of the proposed revisions relate to incorporation of definitions from the NERC Glossary of Terms. For each proposed revision, the FMAG undertook a review to determine whether it was appropriate to incorporate the defined term, given the context and usage of the term in the FM. In some instances, the Glossary term was not used because the FMAG did not believe it had the intended meaning of the defined term, as used in the FM. In some instances, the term was simply capitalized to indicate it had the meaning of the Glossary term. In other instances, the word or phrase was replaced with a defined term (*i.e.*, reliability-related services replaced with Interconnected Operations Service).

2. Consolidated ERO-related functions: In the current version of the FM (version 5), there are separate functions for Standards Developer, Compliance Enforcement Authority and Reliability Assurance. The FMAG believes that all of these fall under one "function" of ensuring the reliability of the BPS. Therefore, all functions related to reliability assurance were moved to the Reliability Assurance function. The Reliability Assurance function is intended to include any tasks performed by the Electric Reliability Organization (ERO) to ensure the reliability of the BPS, including, for example, development of Reliability Standards, development and implementation of a compliance and enforcement program, and development and maintenance of a program for identifying and registering entities responsible for compliance.

3. Clarified the planning functions: Planning Coordinator (PC), Transmission Planner (TP), and Resource Planner (RP): The proposed revisions seek to identify the differences in the various planning functions, the tasks performed by the functional entities, and how the planners work together to ensure the Bulk Electric System (BES) has adequate reliability planning.

4. Clarified how Interchange occurs: The proposed revisions provide clarity regarding how the various functions and functional entities work together to perform Interchange, including incorporation of appropriate Glossary terms (*i.e.*, Requests for Interchange, Arranged Interchange, Confirmed Interchange).

5. Added cyber and physical security tasks: The FMAG is proposing to add two new tasks related to security protections for cyber assets and physical assets, and communication regarding an actual or suspected threat to those assets. The new tasks have been added to the following functions:

- Reliability Coordinator (RC)
- Balancing Authority (BA)
- Transmission Operator (TOP)
- Transmission Owner (TO)
- Interchange Coordinator (IC)
- Distribution Provider (DP)
- Generator Owner (GO)
- Generator Operator (GOP).

45-day informal comment period

The proposed revisions to the FM and FMTD are posted for a 45-day informal comment period. The FMAG will review all comments submitted and incorporate, as appropriate, proposed revisions to the FM and FMTD. In the documents posted for comment, the highlighted language is intended to indicate that the revision relates to a substantive change. The FMAG requests that you focus your comments on these highlighted revisions. Revisions that are not deemed substantive include revisions related to:

- Incorporation of a Glossary term;
- Clarification to the existing language (*i.e.*, use of consistent terminology);
- Changes to the order or manner of presentation of information (*i.e.*, rearrangement of tasks to follow a chronological order of how the tasks are performed);
- Consolidation of related items or removal of redundancies; and
- Changes to reflect how Interchange works, including incorporation of NERC Glossary terms.

Below is a mapping of the proposed revisions, along with an explanation of why the revision was needed necessary.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
1	General (Executive Summary, Introduction, Purpose, etc.)	Consolidated general background information and into one section (Section I – Purpose of the FM).	Provided clear, concise summary of the purpose of the FM; also, explained that the FM is a guideline and not a standard, nor does it identify entities for NERC Registration.
2	Standards Developer	Deleted entire section	See “Reliability Assurer” section

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
3	Compliance Enforcement Authority	Deleted entire section	See "Reliability Assurer" section
4	Reliability Assurer	Revised section to include greater detail regarding the tasks performed by the ERO (and the Regional Entities).	Identified the various tasks performed by NERC (and the Regional Entities) in its role as the ERO.
5	Planning Coordinator	Revised entire section to provide clarity regarding the differences in roles and tasks performed by the planning entities (*i.e.*, Planning Authority, TP, and RP). Also, provided greater clarity regarding how the planners work together to ensure the BES has adequate reliability planning.	New Tasks 1, 2, 3 work together to outline the sequential process followed by the PC to conduct transmission system assessments. The component of "analysis and development of resource adequacy plans" was intentionally removed from the PC tasks. With regard to the assessments performed: • Both the TP and PC perform assessments to evaluate whether future transmission system performance will meet the minimum acceptable system performance requirements. However, the TP and PC may consider different system conditions (and BES facilities) in performing their respective assessments; this flexibility allows for studying a wider range of system conditions and allows for a more complete and comprehensive assessment of the BES. • TP assessment includes the collection of transmission assets over which the TP is responsible for planning ("TP Area"). • PC assessment includes the collection of transmission assets over which the PC is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one TP. The PC focuses on assessments of both Transmission and resource planning for its PC Area. • Every BES facility must have one associated TP and at least one PC. This means that every facility in the TP Area

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
			should be included in the assessment conducted by the TP.
6	Transmission Planner	Deleted Task No. 7: ~~Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.~~	The nature of the TP's work requires that the TP has an understanding of the "typical" system protection and control schemes utilized by the associated Transmission Owner(s). Through interaction with the TO, the TP can also have an influence on the system protection scheme standards that a TO uses. In some instances, the TP may recommend a Remedial Action Scheme (RAS) as a means of addressing Transmission system performance issues. The TP's awareness of, and influence on, system protection schemes were viewed as an integral part of the TPs' modeling and assessment tasks. The FMAG determined that a discussion of the TP's involvement with protection systems was better suited to the FMTD. Therefore the task was deleted.
7	Transmission Planner	Revised Relationship No. 9: Deleted "Resource Planner" and added "Planning Coordinator" "Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Transmission Planner area with other Transmission Planners and the Planning Coordinator~~Resource Planners~~, as appropriate."	Removed "Resource Planner" and added "Planning Coordinator" because the PC is also concerned with transmission system assessments, whereas the RP is not.
8	Transmission Planner	Revised Relationship No. 10: Added "Planning Coordinator"	Added "Planning Coordinator" because of the PCs role and interest in assessing transfer capability.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		"Coordinates and develops transfer capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners ~~and~~ Transmission Service Providers, and the Planning Coordinator."	
9	Resource Planner	Revised entire section to provide clarity and to distinguish resource planning tasks from other planning functions. Also, provided greater clarity regarding how the RPs interact with the TPs and Transmission Service Providers to ensure the BES has adequate resource planning.	Removed the prescriptive language to emphasize the completion of the task versus "how to perform" the task. Also, revised the language to improve clarity of the functional relationships.
10	Reliability Coordinator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 11: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 12: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 11: Additional task necessary to identify RC reliability related responsibilities associated with cyber and physical security. New Task No. 12: Additional task necessary to identify RC communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
11	Reliability Coordinator	Revised Relationship No. 2: Added Distribution Providers	Added DP because the RC receives reliability-related facility and operational data from the DP.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		"Receives facility and operational data from Generator Operators, Distribution Providers, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators."	
12	Reliability Coordinator	Revised Relationship No. 6: "Develop~~s~~ Interconnection Reliability Operating Limits, and provide them to those entities with a reliability-related need~~based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them to Transmission Operators~~."	Revised the relationship to reflect fact that RC establishes IROLs based on a number of factors (not limited to the equipment ratings); and the RC communicates the IROLs to various entities (not solely the TOP) based upon the specific requirements outlined in the RC's methodology or specific procedure in place.
13	Reliability Coordinator	Deleted Relationship No. 12: Duplicative ~~"Provide IROLs and TTC to the Transmission Service Provider for ATC calculation."~~	This is covered in Relationship No. 6.
14	Balancing Authority	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 14: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 15: "Communicate to appropriate authorities and relevant functional	New Task No. 14: Additional task necessary to identify BA reliability related responsibilities associated with cyber and physical security. New Task No. 15: Additional task necessary to identify BA communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		entities of an actual or suspected attack on cyber assets and/or physical assets."	
15	Balancing Authority	Added new Relationship: New Relationship No. 1: "Ahead of Time: Receive generator Facility plans from Generator Operators within the Balancing Authority Area."	Clarifies how and when information is provided from GOP in the BA Area.
16	Balancing Authority	Added new Relationship: New Relationship No. 2: "Ahead of Time: Receive operational data from Generator Operators within the Balancing Authority Area."	Clarifies how and when information is provided from the GO in the BA Area.
17	Balancing Authority	Deleted Relationship No. 2: Duplicative ~~"Receive operating and availability status of generating units from Generator Operators within the Balancing Authority Area."~~	Covered in Relationship No. 14
18	Balancing Authority	Revised Relationship No. 10: Removed GOP. "Implements generator commitment and dispatch schedules from the Load-Serving Entities ~~and Generator Operators~~ who have arranged for generation within the Balancing Authority Area."	Removed GOP because the information is from the LSE, not the GOP. The GOP operates the generator, the LSE has the schedule.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
19	Balancing Authority	Added new Relationship: New Relationship No. 1: "Receive reports on frequency regulating equipment from Generator Operators within the Balancing Authority Area."	Clarifies how and when information is provided associated with frequency regulation from the GOP in the BA Area.
20	Transmission Operator	Revised Task No. 8: "Adjust Real Power, Reactive Power and voltage ~~flow control devices within the transmission area~~ to maintain reliability."	Revised language to improve clarity regarding the task performed, while not limiting or specifying "how" the TOP maintains parameters to ensure reliability.
21	Transmission Operator	Deleted Task No. 9: Duplicative. ~~"Deploy reactive resources to maintain transmission voltage within defined limits."~~	Repeat of Task No. 8.
22	Transmission Operator	Added new Task: New Task No. 9: "Determine the Transmission capability that supports the Reliable Operation of the Transmission Operator Area."	Additional task supports the required Transmission capability assessments required to be completed by the TOP.
23	Transmission Operator	Added new Task: New Task No. 10: "Operate or direct the operation of Transmission Facilities in its TOP Area."	Additional task necessary to correctly identify the TOP responsibilities associated with the operation of the Transmission System.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
24	Transmission Operator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 14: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 15: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 14: Additional task necessary to identify TOP reliability related responsibilities associated with cyber and physical security. New Task No. 15: Additional task necessary to identify TOP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
25	Transmission Operator	Revised Relationship No. 11: "Ahead of time: Provides Total Transfer Capabilities, and System Operating Limits, and methodology for calculating to, and coordinates Available Transfer Capability for respective Transmission paths to with, Transmission Service Provider."	Revised language to improve clarity of the functional relationship.
26	Transmission Operator	Revised Relationship No. 12: "Ahead of time: Receives operating and availability status of generating units from Generatorion Operators including status of automatic voltage regulators and power system stabilizers."	Added "and power system stabilizers" to identify the need of the TOP to be aware of component status.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
27	Transmission Operator	Added new Relationship: New Relationship No.13: "Ahead of time: Receive operational data from Generator Operators."	Additional relationship necessary to ensure that the TOP has all necessary operational data to support Operations Planning functions and real-time contingency analysis.
28	Transmission Operator	Revised Relationship No. 18: "Real-time: Deploy~~s~~ reactive resources from Transmission Owners, ~~and~~ Generator Owners, and Distribution Providers to maintain acceptable voltage profiles."	Relationship expanded to include the DP as an operating authority for reactive resources.
29	Transmission Operator	Added new Relationship: New Relationship No.24: "Real-time: Receive Real-time operating information from Generator Operators."	Additional relationship necessary to ensure that the TOP has all necessary operational data to support real-time contingency analysis.
30	Interchange Coordinator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 9: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 10: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 9: Additional task necessary to identify IC reliability related responsibilities associated with cyber and physical security. New Task No. 10: Additional task necessary to identify IC communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
31	Interchange Coordinator	Added new Relationship: New Relationship No. 7: "Receive reliability alerts from the Reliability Coordinators."	This was a missing reciprocal relationship to an existing RC relationship.
32	Transmission Service Provider	Revised Task No. 2: "Determine and post available transfer ~~capability~~ capacity values."	Changed capability to capacity to avoid Glossary conflict.
33	Transmission Service Provider	Added new Task: New Task No. 5: "Acquire Ancillary Services to support Transmission Service."	Added task to recognize provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.
34	Transmission Service Provider	Added new Task: New Task No. 6: "Update information that is relevant to a long-term Transmission Service arrangement."	Added task to support an existing reciprocal relationship with TP.
35	Transmission Service Provider	Added new Relationship: New Relationship No. 1: "Ahead of Time: Receive the methodology to determine available transfer capacity from the Transmission Operator."	Added relationship to recognize TOP responsibility to develop methodology.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
36	Transmission Service Provider	Revised Relationship No. 1: "Ahead of Time: Receive~~s~~ Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from ~~Planning Coordinator,~~ the Transmission Planner, Transmission Operator and Reliability Coordinator, and coordinates ~~A~~available ~~T~~transfer capacity ~~Capability~~ with these entities and other Transmission Service Providers."	Deleted PC. Changed ATC to available transfer capacity to avoid Glossary conflict.
37	Transmission Service Provider	Revised Relationship No. 3: "Ahead of Time: Receive~~s~~ ~~t~~Transmission expansion plans identified by the Transmission Planner(s)~~Planning Coordinator~~ to help determine ability to accommodate long-term transmission service requests."	Changed PC to TP.
38	Transmission Service Provider	Added new Relationship: New Relationship No. 4: "Ahead of Time: Arrange for providers of Ancillary Services, and notify the Transmission Operator and Balancing Authority."	Supports newly added task to provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.
39	Transmission Service Provider	Added new Relationship:	Supports newly added task to provider of last resort responsibilities for required Ancillary Services to support Transmission Services in the Open Access Transmission Tariff.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		New Relationship No. 15: "Notify the Transmission Operator and Balancing Authority of changes to Ancillary Services."	
40	Transmission Owner	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 6: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 7: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 6: Additional task necessary to identify TO reliability related responsibilities associated with cyber and physical security. New Task No. 7: Additional task necessary to identify TO communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
41	Transmission Owner	Revised Relationship No. 1: "Coordinates with Transmission Planners and the Planning Coordinator, Generator Owners, other Transmission Owners, and Load-Serving Entities desiring to connect with the Bulk Electric System."	Deleted GO and LSE. Clarified scope.
42	Transmission Owner	Revised Relationship No. 9: "Develops interconnection agreements with the Distribution Providers and Generation Owners for connecting to the Bulk Electric System."	Deleted LSE.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
43	Distribution Provider	Revised Task No. 1: "Provide and operate electrical delivery ~~f~~Facilities between the ~~t~~Transmission system and the ~~E~~end-~~u~~Use ~~C~~customer or distribution-connected energy resource."	Added "distribution-connected energy resource" to recognize increasing number of these types of resources that impact the amount of energy supplied to the BES.
44	Distribution Provider	Added New Task: New Task No. 2: "Identify and characterize its connected load and energy resources."	DP should understand the characteristics of the load and resources connected to its system, which can have an impact on the BES performance.
45	Distribution Provider	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 7: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 8: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 7: Additional task necessary to identify DP reliability-related responsibilities associated with cyber and physical security. New Task No. 8: Additional task necessary to identify DP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
46	Distribution Provider	Revised Relationship No. 1: "Ahead of time: Coordinate~~s~~ with Transmission Planners on interconnected load and energy	Added energy resources instead of only load.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		resources to support ~~t~~Transmission analysis~~expansion~~."	
47	Distribution Provider	Revised Relationship No. 3: "Ahead of time: Coordinate~~s~~ with ~~E~~end-use ~~C~~customers, distributed energy resources, and Load-Serving Entities to identify new ~~f~~Facility connection needs."	Added "distribution-connected energy resource" to recognize increasing number of these types of resources that impact the amount of energy supplied to the BES.
48	Distribution Provider	New Relationship added: New Relationship No. 7: "Ahead of time: Provide protective relaying systems, under-frequency Load shedding systems, under-voltage Load shedding systems, and Remedial Action Schemes as defined by the Transmission Planner and Planning Coordinator."	Relationship added to support existing Task No. 4
49	Distribution Provider	New Relationship added: New Relationship No. 8: "Real-time: Obtain voltage and power factor requirements from the Transmission Operator."	Relationship added to support existing Task No. 6
50	Generator Operator	Revised Task No. 5: "Support Interconnection frequency and voltage."	Accounted for GOP task of contributing to voltage support.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
51	Generator Operator	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 6: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 7: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 6: Additional task necessary to identify GOP reliability related responsibilities associated with cyber and physical security. New Task No. 7: Additional task necessary to identify GOP communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
52	Generator Operator	Revised Relationship No. 3: "Ahead of Time: Provide~~s~~ availability and operating ~~and availability~~ status of generator~~ing~~ Facilities~~units~~ to Reliability Coordinator, Balancing Authority and Transmission Operators for reliability analysis."	Added RC.
53	Generator Operator	Revised Relationship No. 4: "Ahead of Time: Report~~s~~ status of automatic voltage regulating equipment and power system stabilizer equipment ~~or frequency regulating equipment~~ to Transmission Operators."	Deleted frequency regulating equipment; added as a new task.
54	Generator Operator	Added new Relationship:	Added new Relationship to support existing Task.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		New Relationship No. 5: "Ahead of Time: Report on frequency regulating equipment to Balancing Authority."	
55	Generator Operator	Revised Relationship No. 5: "Ahead of Time: Provides operational data to Reliability Coordinator, Balancing Authority and Transmission Operator."	Added BA and TOP.
56	Generator Owner	Added new Tasks: Added two new tasks regarding cyber and/or physical security. New Task No. 5: "Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data." New Task No. 6: "Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets."	New Task No. 5: Additional task necessary to identify GO reliability related responsibilities associated with cyber and physical security. New Task No. 6: Additional task necessary to identify GO communication responsibilities associated with actual or suspected attacks on cyber assets and/or physical assets.
57	Generator Owner	Revised Relationship No. 2: "Provide~~s~~ Facility~~unit~~ maintenance schedules and ~~unit~~ generator Facility retirement plans to the Reliability Coordinator, Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner."	Added RC.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
58	Generator Owner	Revised Relationship No. 7: "Revises the generator~~ion~~ maintenance plans as requested by the Balancing Authority, Transmission Operator, and Reliability Coordinator."	Added BA and TOP.
59	Purchasing-Selling Entity	Added New Relationship No. 1: Arrange for energy and capacity from Generator Owners.	Added missing reciprocal relationship for Task No. 1.
60	Load-Serving Entity	Revised Task No. 3: "Identify and communicate ~~Participate in under-frequency load shedding systems and under-voltage load shedding systems through identification of~~ critical customer loads that are to be excluded from the load shedding systems."	Added communication element.
61	Load-Serving Entity	Revised Relationship No. 1: "Ahead of Time: Submit~~s~~ load data~~profiles and characteristics, plans, and forecasts~~ as needed to the appropriate entity (*e.g.*, Balancing Authorities, ~~Purchasing-Selling Entities, Planning Coordinator,~~ Resource Planners, and Transmission Service Providers~~Planners~~) in	Link the load data submission need and types to applicable tariff, interconnection agreements or other arrangements as opposed to a generic set.

ID No	Section or Function	Revision / Action Taken	Explanation / Basis for Revision
		accordance with applicable tariffs, interconnection agreements or other arrangements."	
62	Load-Serving Entity	Revised Relationship No. 2: "Ahead of Time: Coordinate with Distribution Provider to identify critical loads that are to be excluded from load-sheddingIdentifies new facility connection needs for End-use Customers."	Clarify that the DP is the entity impacted by the identified information.
63	Load-Serving Entity	Revised Relationship No. 12: "Real-time: Receives requests from the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider for voluntary load cCurtailment."	Added RC and TOP, who also make these requests.
64	Load-Serving Entity	Revised Relationship No. 13: "Real-time: Communicate requests for voluntary load cCurtailment to end-use customers as directed by the Reliability Coordinator, Balancing Authority, Transmission Operator and Distribution Provider."	Added RC and TOP, who also make these requests.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Functional Model

~~Function Definitions and Functional Entities~~

Version 6~~5~~

Prepared by the Functional Model Advisory Group
Approved by the Standards Committee: [Month, Year]

RELIABILITY | ACCOUNTABILITY






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Section I: Purpose of the Functional Model~~Part 1: Foreword~~

The functional model (FM) is a guideline that identifies the functions that must be performed to ensure that the Bulk Power System is planned and operated in a reliable manner. The FM describes, in general terms, the functions that must be performed to ensure reliability, the specific tasks that are necessary to perform each function, and the relationships between functional entities that perform the various tasks. In its capacity of a guideline, the FM serves to provide a framework for NERC Reliability Standards as they are developed through the standard development process. The FM is independent of any particular organizational or market structure. The focus of the FM is solely on identification of reliability-related functions and the associated tasks and relationships.

Equally important to explaining what the FM does do, is a clear explanation of what the FM does **not** do. The FM is **not** a mandatory and enforceable document. The FM is **not** a "standard" and does not have compliance effects. If there is a conflict between the FM and Reliability Standards, the Reliability Standards always take precedence. The FM is only a guideline serving to provide details on how the different functions work together to ensure the reliability of our BPS. Also, the FM is **not** intended to identify the entities responsible for NERC registration. The NERC registration process is undertaken by NERC (and the Regional Entities) pursuant to authority from FERC, ultimately derived from the Federal Power Act. The FM has no authority, ability, or intent to impact or influence the NERC Registration process. Below is an overview of the NERC Registration process, which is completely separate from, and should not be confused with, the FM guideline. Similar to conflicts with Reliability Standards, if the FM and NERC Registration do not align, NERC Registration takes precedence.

~~This document replaces version 4 of the NERC Reliability Functional Model that the NERC Standing Committees approved in September 2008.~~

~~Historically, Control Areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers' electricity needs. The traditional Control Area operator balanced its load with its generation, implemented Interchange Schedules with other Control Areas, and ensured transmission reliability.~~

~~As utilities began to provide transmission service to other entities, the Control Area also began to perform the function of Transmission Service Provider through tariffs or other arrangements. NERC's Operating Policies reflected this traditional electric utility industry structure, and ascribed virtually every reliability function to the Control Area.~~

~~Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by Control Areas began to change to reflect the newly emerging industry structure. These changes occurred because:~~

1. ~~Some utilities were separating their transmission from their merchant functions (functional unbundling), and even selling off their generation;~~
2. ~~Some states and provinces were instituting "customer choice" options for selecting energy providers; and,~~
3. ~~The developing power markets were requiring wide-area transmission reliability assessment and dispatch solutions, which were beyond the capability of many Control Areas to perform.~~

~~As a result, the NERC Operating Policies in place at that time, which centered on Control Area operations, were beginning to lose their focus, and become more difficult to apply and enforce.~~

~~The NERC Operating Committee formed the Control Area Criteria Task Force (CACTF) in 1999 to address this problem. The task force began by listing all the tasks required for maintaining electric system reliability and then~~

~~organizing these tasks into basic groups that it called "functions." Ultimately, the Task Force decided to build a "Functional Model." This involved breaking down the previous reliability functions more finely, such that all organizations involved in ensuring reliability —whether they are traditional, vertically integrated control areas, regional transmission organizations, independent system operators, independent transmission companies or so on— can identify those functions they perform, and register with NERC as one or more of the functional entities. Initially the Model dealt with operating functions, but it was subsequently expanded in Version 2 to incorporate planning-related functions. This Functional Model framework provides guidance to NERC standards drafting teams to write reliability standards in terms of the functional entities who perform the reliability functions.~~

~~Adapted from Version 2 of the NERC Functional Model, February 10, 2004.~~

Section II: Overview of the NERC Registration Process~~Part 2: Introduction~~

The NERC Registration process consists of several elements, including the NERC Registry Criteria and the NERC Compliance Registry, and involves both the Regional Entities and NERC. The process for registration is described in the NERC Rules of Procedure, Section 500 (Appendix 5A: Organization Registration and Certification Manual and Appendix 5B: Statement of Compliance Registry Criteria).

The starting point for the NERC program for monitoring and enforcing compliance with FERC-approved Reliability Standards is the process for comprehensively identifying and registering owners, operators, and users of the Bulk Power System that are responsible for performing reliability-related functions in accordance with the approved Reliability Standards.[1] The NERC Registry Criteria provides for Bulk Power System users, owners and operators that perform a function identified in Section II of the Registry Criteria, and have a material impact on Bulk Power System reliability (which is generally determined by whether they meet the threshold criteria in Section III of the Registry Criteria) to register as one or more of fifteen functions. NERC and the Regional Entities identify such entities, which are then obligated to comply with Commission-approved Reliability Standards.[2] Identified entities are registered and included on the NERC Compliance Registry.[3] The NERC Compliance Registry identifies the reliability functions that each registered entity is responsible for meeting pursuant to the requirements of Reliability Standards. Organizations listed in the NERC Compliance Registry are responsible for knowing the contents of, and complying with, Reliability Standards applicable to the reliability function(s).[4] The registration criteria for the reliability functions are specified in the NERC Statement of Compliance Registry Criteria.[5]

The potential costs and effort of registering every organization potentially within the scope of "owner, operator, and user of the BPS," while ignoring their impact upon reliability, would be disproportionate to the improvement in reliability that would reasonably be anticipated from doing so. Therefore, the two stated goals for registration are: (1) consistency between and among Regional Entities and across the continent in the application of the criteria for registering entities; and (2) registration of any entity whose facilities or operations are deemed material to the reliability of the Bulk Power System, irrespective of other considerations.[6]

~~The NERC Reliability Functional Model provides the framework for the development and applicability of NERC's Reliability Standards as follows:~~

- ~~The Model describes a set of Functions that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to~~

[1] *See*, Order on Electric Reliability Organization Risk Based Registration Initiative and Requiring Compliance Filing, Docket No. RR15-4-000, 150 ¶ 61,213 (March 15, 2015).

[2] Section 215(b)(2) of the Federal Power Act (FPA) requires all users, owners and operators of the Bulk Power System to comply with Reliability Standards approved by the Commission. Similarly, the Commission's regulations at 18 C.F.R. §39.2 and §40.2 require all users, owners, and operators of the Bulk-Power System to comply with applicable Reliability Standards and applicable rules of the ERO and Regional Entities approved by the Commission.

[3] NERC Statement of Compliance Registry Criteria (Registry Criteria) at 2 ("Organizations will be responsible to register and to comply with approved Reliability Standards to the extent that they are owners, operators, and users of the Bulk Power System, perform a function listed in the functional types identified in Section II of this document, and are material to the Reliable Operation of the interconnected Bulk Power System as defined by the criteria and notes set forth in this document.").

[4] *See*, NERC Rules of Procedure §501. The current categories of reliability functional entities are listed in Rules of Procedure Appendix 5B, Statement of Compliance Registry Criteria.

[5] *See*, NERC Rules of Procedure, Appendix 5B.

[6] *See*, NERC Rules of Procedure, Appendix 5B at 4.

a functional entity, that is, the entity that performs the function. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions).

- NERC's Standards Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a functional entity (that is defined in the Model and NERC's Glossary). This is possible because a given standard requirement will typically be related to a Task within a Function. A standard requirement will be very specific, whereas a Task in the Model will be more general in nature.
- NERC's compliance processes require specific organizations to register as the entities responsible for complying with standards requirements assigned to the applicable entities.
- The Model's Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.

The Model is a guideline for the development of standards and their applicability. The Model it is not a Standard and does not have compliance requirements. Standards developers are not required to include all tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that address functions not described in the model. Where conflicts or inconsistency exist, the Reliability Standards requirements take precedence over the Model.

The Model is independent of any particular organization or market structure. An organization may perform more than one Function.

The Functional Model describes a functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term "functional entity", is a guideline and cannot prescribe responsibility. It is NERC's compliance processes, backed by regulatory authority, that specify the manner in which, a functional entity is "legally responsible" for meeting the standards requirements assigned to that functional entity.

The work performed to meet the requirements may be self-performed or performed by others.

Functional Model maintenance. The Functional Model is maintained by the Functional Model Working Group (FMWG) under the direction of the NERC Standards Committee, with technical content in the Model and accompanying technical document approved by the Standing Committees (OC, PC and CIPC).

Technical discussions. The companion document, "Functional Model – Technical Discussions," provides additional details on the Functions themselves, how organizations can "roll up" those Functions they wish to perform, and how organizations as "functional entities" interrelate.

The following terms are used in the Functional Model and do not appear in the NERC Glossary.

Functional Entity. The term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function.

Function. A set of related reliability Tasks.

Task. One of the elements that make up a Function in the Functional Model.

Customer. The term applies to a customer for transmission, capacity or energy services (a Purchasing-

Selling Entity, Generator Owner, Load-Serving Entity, or End-use Customer).

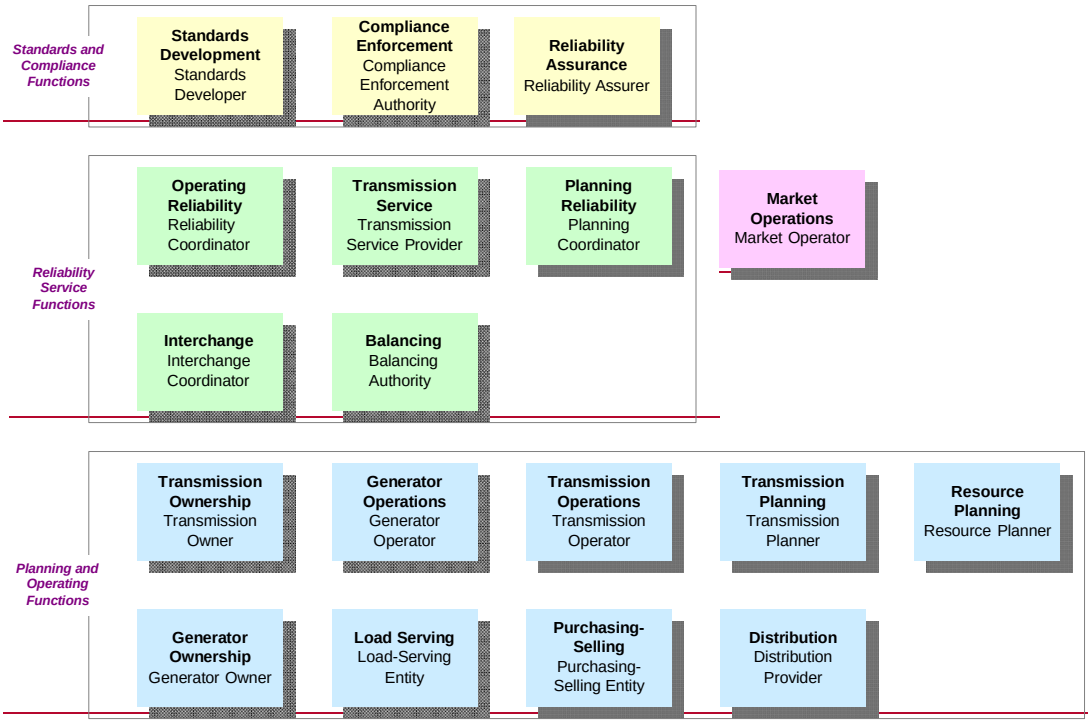
End-use Customer. The party served by a Load-Serving Entity (energy) and Distribution Provider (wire service).

Purpose of the Functional Model

The purpose of the NERC Reliability Functional Model is to:

1. Provide a framework for Reliability Standards developed through the NERC standards development process that will apply to certain Tasks defined in the Functional Model.
2. Describe in general terms each Function and the relationships between the entities that are responsible for performing the Tasks within the Functions. The framework for developing the Function definitions is:
   a. The Functions are independent of the organization structure performing the functions, and
   b. The Functions provide flexibility to accommodate the range of presently conceivable organization structures, as well as accommodate alternative tools, procedures and processes.

~~Functional Model Diagram~~



~~Function Name~~	~~Functional Entity~~
~~Balancing~~	~~Balancing Authority~~
~~Compliance Enforcement~~	~~Compliance Enforcement Authority~~
~~Distribution~~	~~Distribution Provider~~
~~Generator Operations~~	~~Generator Operator~~
~~Generator Ownership~~	~~Generator Owner~~
~~Interchange~~	~~Interchange Coordinator~~
~~Load-Serving~~	~~Load-Serving Entity~~
~~Market Operations~~	~~Market Operator (Resource Integrator)~~
~~Operating Reliability~~	~~Reliability Coordinator~~
~~Planning Reliability~~	~~Planning Coordinator~~
~~Purchasing-Selling~~	~~Purchasing-Selling Entity~~
~~Reliability Assurance~~	~~Reliability Assurer~~
~~Resource Planning~~	~~Resource Planner~~
~~Standards Development~~	~~Standards Developer~~
~~Transmission Operations~~	~~Transmission Operator~~
~~Transmission Ownership~~	~~Transmission Owner~~
~~Transmission Planning~~	~~Transmission Planner~~
~~Transmission Service~~	~~Transmission Service Provider~~

Guiding Principles of the Functional Model

As explained in the Introduction, the Model provides the framework on which the NERC Reliability Standards are developed and applied. To ensure that this framework remains viable, the Model itself is governed by a set of "guiding principles" that define a Function's Tasks and establish the relationships between the functional entities which are responsible for meeting the requirements in the NERC Reliability Standards that correspond to these Tasks. These principles serve as a guideline to those revising or interpreting the Model.

For further details, refer to the Technical Discussions section in the Functional Model Technical Document.

0. The Model must be *complete*, that is, it must include all reliability Tasks and interrelationships between entities performing them. This helps ensure that any reliability requirement arising in a Reliability Standard will generally be related to a Task in the Model and therefore be assignable to a particular functional entity.

0. The Model must group these Tasks into a set of Functions, such that:

    - There are enough Functions (and corresponding functional entities) to accommodate the full range of organization structures and responsibilities within the industry, and

    - The number of Functions is developed based on logical grouping of the Tasks and kept low as reasonably possible.

        - In particular, where a number of organizations that perform a given Function form a single group, the Model recognizes this as a business arrangement among organizations, not a new Function and corresponding new functional entity. That is, the fundamental reliability Tasks, and hence the Function, remain the same – all that has changed is *how* the Function is performed. Examples of such groups are a reserve sharing group (a collection of entities that are Balancing Authorities), or a planned resource sharing group.

0. The Model is structured to ensure there are no gaps or overlaps in the performance of operation Tasks in the operating timeframe anywhere in the Bulk Electric System. This is achieved in part by associating an "area" of purview for each functional entity. Areas are defined in term of the individual transmission, generator and customer equipment assets that collectively constitute the Bulk Electric System. For example, each Bulk Electric System asset has one Reliability Coordinator, one Balancing Authority, and one Transmission Operator. Regarding overlaps for planning, as described in the Technical Document, it is not always possible to achieve this in the case of planning Functions, where there may be overlapping levels of responsibility for given assets. Questions regarding relationships between the areas of different functional entities, such as whether one type of area must be totally within another type of area, will be defined in Reliability Standards or the Rules of Procedure, not the Model.

0. Tasks describe *what* is to be done, not *how* it is to be done.

0. The Model is a guideline that describes reliability Tasks and interrelationships between the entities that perform them – it is not prescriptive. In particular, the Model does not address requirements for registering or becoming certified as a functional entity, or the delegation or splitting of responsibility for meeting standards requirements.

~~Clarification Service~~

~~The Functional Model is a reference tool that links functional entities with associated reliability- related functions and respective Tasks. Drafting teams use the Functional Model to help them determine which functional entity should be required to comply with each requirement in a reliability standard.~~

~~From time to time questions of clarification and interpretation arise. The FMWG is following the process described below for handling requests for clarification of the Functional Model. This process, which has been approved by the Standards Committee, is accessible to all drafting teams as well as any other interested stakeholders. If a drafting team needs help in understanding Tasks that make up a Function and/or in determining which functional entities should be responsible for particular standards requirements, the drafting team's coordinator will send an e-mail to the NERC Staff assigned as the FMWG facilitator with a request for clarification.~~

0. ~~The NERC Staff assigned as the FMWG facilitator will convene a conference call/meeting of available members of the FMWG to review the question(s) and provide a clarification.~~
    - ~~If the question(s) need more detailed discussion with the drafting team, the two coordinators will organize a conference call/meeting with available members of the FMWG and available members of the drafting team to discuss the issues in more detail.~~
0. ~~Each FMWG request for clarification and the associated response will be posted on the NERC Functional Model Web Page under a Frequently Asked Questions section.~~
    - ~~If the questions result in changes to the model, the changes will be added to a change summary table used to develop the next updated version of the Functional Model document.~~

Section III: ~~Part 3:~~ Functions and Functional Entities

This section defines the reliability-related functions and functional entities that perform the associated ~~T~~tasks that are necessary to plan and operate the Bulk Electric System in a reliable manner. This section also identifies the relationships between various functional entities that are formed in order to perform the reliability-related tasks. ~~characterizes the functional entities that perform these Tasks, and provides examples of the inter-relationships that take place between entities to ensure reliability. As standards are developed, the Model may be revised to add and remove Tasks under specific Functions to aid in the development of standards. Relationships between functional entities in the Model are reciprocal. Where~~ In some instances, a one-to-one relationship may exist~~s~~ between two functional entities; in other instances, there may be ~~, the Model will include the reciprocal relationship specifically; and where~~ a one-to-many relationship. ~~exists, the reciprocal relationships are implied.~~

~~Functional Model Diagram~~

~~Standards Development and Standards Developer~~

~~Standards Development~~

~~Tasks~~

~~0. Develop and maintain a standards development process.~~

~~0. Develop Reliability Standards for the planning and operation of the Bulk Electric System.~~

~~Standards Developer~~

~~Definition~~

~~The functional entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.~~

~~Introduction to the Standards Developer~~

~~The Model addresses Reliability Standards created at NERC using the NERC Reliability Standards Development Procedure and Regional Standards that are created through an open Regional process and approved by NERC for enforcement. The Functional Model is intended to serve as the framework for the development and application of these Reliability Standards.[7]~~

~~Relationships with Other Functional Entities~~

- ~~0. Receives request for Reliability Standards through the public process.~~
- ~~0. Sends Reliability Standards to the Compliance Enforcement Authority.~~

~~[7] There are also Regional Criteria that are requirements that Regions create and enforce, that are not included in the Model.~~

~~Compliance Enforcement and Compliance Enforcement Authority~~

~~Compliance Enforcement~~

~~Tasks~~

~~0. Develop, maintain and implement a compliance enforcement process.~~

~~0. Evaluate and document compliance.~~

~~Compliance Enforcement Authority~~

~~Definition~~

~~The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.~~

~~Relationships with Other Functional Entities~~

~~2. Receives Reliability Standards from the Standards Developer.~~

~~3.~~**1.** ~~Administers the compliance enforcement process for all functional entities as required by Reliability Standards.~~

Reliability Assurance and Reliability Assurer

Reliability Assurance

Tasks

1. Develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable the Reliability Assurer to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems.
2. Develop and implement a compliance and enforcement program to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North American in which the Reliability Assurer has been given enforcement authority.
3. Develop and maintain a program for identifying and registering those entities that are responsible for compliance with the governmental-approved Reliability Standards.
4. Provide for certification of all entities with primary reliability responsibilities requiring certification.
5. Provide a mechanism to ensure system operators are provided the education and training necessary to obtain the essential knowledge and skills and are therefore qualified to operate the BES.
6. Provide reliability readiness evaluation and improvement, and formation of sector forums if necessary for reliability.
7. Develop a reliability assessment and performance analysis program that conducts reviews and assessments of the overall reliability of the interconnected BPS, including:
    - Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.
    - Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.
    - Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.
    - Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.
    - Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.
8. Provide leadership, coordination, technical expertise, and assistance to the industry in responding to a major event.
9. Provide the education and training necessary for Bulk Power System personnel and regulators to obtain the essential knowledge necessary to understand and operate the BES.
10. Through the use of appropriate functional entities and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary.

11. Coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure.

~~1. Coordinate reliability assurance among adjacent Reliability Assurers through the development of necessary protocols and processes.~~

~~1. Coordinate the activities related to maintaining critical infrastructure protection.~~

~~1. Establish reliability assurance processes and documentation related to planning and operations within the Reliability Assurer's area including such things as a regional reliability plan or a Reliability Coordinator plan.~~

~~1. Identify and address gaps in reliability processes and responsibilities.~~

Reliability Assurer

Definition

Subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada, assure the reliability of the Bulk Power System in North America by developing and enforcing Reliability Standards; annually assessing seasonal and long-term reliability; monitoring the Bulk Power System through system awareness; and, educating, training, and certifying industry personnel. ~~The functional entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer area and adjacent areas.~~

Relationships with Other Functional Entities

1. Develop Reliability Standards that identify the functional entities responsible for complying with the Reliability Standard, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

2. Obtain the information necessary to monitor compliance with Reliability Standards from functional entities, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

3. Obtain the information necessary to complete registration from the appropriate functional entities, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

~~0. Coordinates reliability assurance activities of the functional entities within the Reliability Assurer area.~~

~~0. Coordinates reliability assurance activities with adjacent Reliability Assurers.~~

~~0. Coordinates critical infrastructure protection programs with functional entities.~~

~~0. Collects information from functional entities related to Reliability Assurance processes.~~

Planning Reliability and Planning Coordinator

Planning Reliability

Tasks

1. Establish data requirements necessary to develop power system models for analysis within the Planning Coordinator area. ~~Develop and maintain methodologies for the analysis and simulation of the transmission systems in the evaluation and development of transmission expansion plans and the analysis and development of resource adequacy plans.~~

2. Collect and validate information from Transmission Planners, such as modeling data, to perform a Transmission assessment of the Planning Coordinator area. ~~Define information required for planning purposes, and facilitate the process for consolidating and collecting or developing such information, including:~~

   - ~~Transmission facility characteristics and ratings.~~
   - ~~Demand and energy forecasts, capacity resources, and demand response programs.~~
   - ~~Generator unit performance characteristics and capabilities.~~
   - ~~Long-term capacity purchases and sales.~~

~~7.~~3. Assess the performance of the Transmission system, with the loads, resources, and proposed projects included in the Transmission Planner's Planning Assessment (including any Corrective Action Plan(s)). ~~Evaluate, develop, document, and report on resource and transmission expansion plans for the Planning Coordinator area. Integrate the respective plans, evaluate the impact of those plans on and by adjoining Planning Coordinator's integrated plans and assess whether the integrated plan meets reliability needs, and, if not, then to report on potential transmission system and resource adequacy deficiencies and suggest or facilitate the process for developing alternative plans to mitigate identified deficiencies.~~

   - ~~Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.~~
   - ~~Review transmission facility plans required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.~~
   - ~~Review and determine transfer capability (generally one year and beyond) as appropriate.~~
   - ~~Monitor and evaluate transmission expansion plan and resource plan implementation.~~
   - ~~Coordinate projects requiring transmission outages that can impact reliability and firm transactions.~~

~~13.~~4. Coordinate with adjoining Planning Coordinators to develop interconnection models with appropriate loads, resources, and System topology. ~~so that system models and resource and transmission expansion plans take into account modifications made to adjacent Planning Coordinator areas.~~

5. Evaluate and report on the performance of the consolidated Transmission assessments. ~~Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.~~

~~14.~~6. Evaluate interconnection reliability concerns among affected Planning Coordinators.

Planning Coordinator

Definition

The ~~functional~~ responsible entity that coordinates ~~, facilitates,~~ and integrates ~~and evaluates (generally one year and beyond)~~ transmission ~~f~~Facilit~~ies~~y and service plans, ~~and~~ resource plans, and Protection Systems.[8] ~~within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.~~

Introduction to the Planning Coordinator

By its very nature, BES planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. The Planning Coordinator is responsible for coordinating the assessment~~ing~~ of the BES within its ~~the longer-term reliability of its~~ Planning Coordinator area. The PC assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one Transmission Planner; however, ~~While~~ the area under the purview of a Planning Coordinator may include as few as one Transmission Planner~~, and one Resource Planner,~~ ~~t~~The Planning Coordinator's scope of activities is intended to span a broader area that may include BES assets of multiple Transmission Planners. All BES Facilities should be assigned to a Transmission Planner and to a Planning Coordinator, so that there are no gaps in the assessment of the BES. ~~may include extended coordination with integrated Planning Coordinators' plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems.~~ Planning Coordinators work through a variety of processes ~~mechanisms~~ to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all portions of the interconnected BES ~~network areas with little or no ties to others' areas, such as interconnections,~~ are completely coordinated for planning activities.

Relationships with Other Functional Entities

1. Establish ~~Coordinates~~ power system modeling data requirements in conjunction with interconnected ~~and collects data for system modeling from~~ Transmission Planners ~~Resource Planner,~~ and other Planning Coordinators.
2. Collect data for power system modeling and assessments from the Transmission Planner.
~~2.~~3. Determine ~~Coordinates~~ transfer capability ~~(generally one year and beyond)~~with ~~Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and~~ neighboring Planning Coordinators.
~~3.~~4. Exchange information on ~~Coordinates~~ Contingencies, criteria, System Operating Limits (SOLs), Remedial Action Schemes (RAS), automatic load-shedding schemes, and plans with the Reliability Coordinator and other Planning Coordinators ~~on reliability issues~~.
~~4.~~5. Assess the performance of the Transmission system, in coordination with Transmission Planners~~Receives plans from Transmission Planners and Resource Planners~~.
~~5. Collects information including:~~
   - ~~Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.~~
   - ~~Demand and energy forecasts, capacity resources, and demand response programs from~~

[8] Definition of Planning Authority from the NERC Glossary of Terms (as of May 15, 2016). In the Glossary, Planning Coordinator and Planning Authority are defined interchangeably.

~~Load-Serving Entities, and Resource Planners.~~

~~. Generator unit performance characteristics and capabilities from Generator Owners.~~

~~. Long-term capacity purchases and sales from Transmission Service Providers.~~

~~10.~~6. Collect~~s~~ and review~~s~~ reports on ~~t~~Transmission, loads and resource~~s plan implementation~~ from ~~Resource Planners and~~ Transmission Planners.

~~11. Submits and coordinates the plans for the interconnection of facilities to the Bulk Electric System within its Planning Coordinator area with Transmission Planners and Resource Planners and adjacent Planning Coordinator areas, as appropriate.~~

~~12. Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system.~~

~~13.~~7. Facilitate~~s~~ the integration of the respective plans of the ~~Resource Planners and~~ Transmission Planners within the Planning Coordinator area, and adjacent Planning Coordinator areas, as appropriate.

a. Review~~s~~ the integrated plan with respect to established reliability needs considering the impact on and by adjoining ~~s~~Systems.

b. In coordination with the ~~Resource Planners and~~ Transmission Planners, facilitate~~s~~ the development of alternative solutions for plans that do not meet those reliability performance criteria ~~needs~~.

Transmission Planning and Transmission Planner

Transmission Planning

Tasks

1. Develop and ~~M~~maintain ~~and develop, in cooperation with adjacent and overlapping Transmission Planners,~~ methodologies, criteria and tools for the analysis and simulation of the ~~t~~Transmission systems ~~in the evaluation and development of transmission expansion plans related to resource adequacy plans~~.

2. ~~Define, consolidate and collect or d~~Develop, acquire and validate~~, in cooperation with adjacent and overlapping Transmission Planners,~~ information required for Transmission assessments~~planning purposes~~ including:

    a. Transmission ~~f~~Facility characteristics and ~~r~~Ratings.

    b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and Demand-Side Management (DSM) ~~demand response~~ programs.

    c. Generator unit performance characteristics and capabilities.

    d. Commitments for firm Transmission Interchange.~~Long-term capacity purchases and sales~~

    e. Load forecasts and generation dispatch scenarios.

3. Develop and ~~M~~maintain ~~transmission~~ power system models (steady state, dynamics, and short circuit) necessary for the assessment of Transmission system ~~to evaluate Bulk Electric System~~ performance for identified scenarios.

4. Exchange information with other ~~Coordinate with adjacent and overlapping~~ Transmission Planners and the Planning Coordinator to achieve an interconnected ~~so that system~~ model~~s and resource and transmission expansion plans take into account modifications made to adjacent and overlapping Transmission Planner areas~~.

5. ~~Evaluate, develop, document, and report on expansion plans for the Transmission Planner area.~~ Assess the performance of the Transmission system with the anticipated topology and scenarios of loads and resources ~~whether the integrated plan meets reliability needs, and, if not, report on potential network conditions or configurations that do not meet performance requirements and provide potential alternative solutions to meet performance requirements~~.

    ~~. Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.~~

    ~~. Evaluate and plan for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.~~

    ~~. Determine transfer capability values (generally one year and beyond) as appropriate.~~

    ~~. Monitor, evaluate and report on transmission expansion plan and resource~~

plan implementation.

- Coordinate projects requiring transmission outages that can impact reliability and firm transactions.

5. Notify Generation Owners, Resource Planners, Transmission Planners and Transmission Owners of any planned transmission changes that may impact their facilities.

5. Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.

Transmission Planner

Definition

The ~~functional~~ entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority ~~a Transmission Planner~~ area.[9]

Introduction to the Transmission Planner

The Transmission Planner is responsible for assessing the long~~er~~ term (generally one year and beyond) Transmission system performance within ~~reliability of~~ its Transmission Planner area. The TP assessment includes the collection of Transmission assets over which the Transmission Planner is responsible for planning ("TP Area"). By its very nature, BES~~ulk Electric System~~ planning involves multiple entities. Since all electric ~~s~~Systems within an integrated network are electrically connected, changes planned in ~~whatever~~ one part of the ~~s~~System ~~does~~ can affect the other parts of the ~~s~~System~~s~~. Transmission Planners coordinate their plans with the adjoining Transmission Planners to assess impact on or by those plans. The area under the purview of a Transmission Planner may include one or more Resource Planner areas~~ and overlap one or more adjacent Transmission Planners.~~ All BES Facilities should be under the purview of at least one Transmission Planner.

Relationships with Other Functional Entities

1. Coordinate~~s~~ and collect~~s~~ data (steady state, dynamics, and short circuit) for power system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, Resource Planners~~, other Transmission Planners,~~ Transmission Owners, ~~and~~ Transmission Service Providers, and other Transmission Planners.
2. Collect~~s~~ information including:
    a. Transmission facility characteristics and ~~r~~Ratings from the Transmission Owners, Transmission Planners, and Transmission Operators.
    b. Demand and Electrical ~~e~~Energy forecasts, capacity resources, and ~~d~~Demand-Side Management ~~response~~ programs from Load-Serving Entities, and Resource Planners.
    c. Generator unit performance characteristics and capabilities from Generator Owners.
    d. Commitments for firm Transmission Interchange ~~Long-term transmission capacity purchases and sales~~ from Transmission Service Providers.
3. Inform~~s~~ Resource Planners and other Transmission Planners of the methodologies and tools for the simulation of the ~~t~~Transmission system.

~~4. Coordinates with Resource Planners and other Transmission Planners on Bulk Electric System expansion plans.~~

~~5.~~4. Coordinate~~s~~ ~~the evaluation of~~ BES~~ulk Electric System~~ expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

~~6.~~5. Report~~s~~ on and coordinate~~s~~ its BES~~ulk Electric System~~ expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service

[9] Definition of Transmission Planner from the NERC Glossary of Terms (as of May 15, 2016).

Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

~~7.~~6. Notify~~ies~~ other Transmission Planners, Transmission Owners, Transmission Operators and other entities that may be impacted by~~of~~ any planned BES~~ulk Electric System~~ changes.

~~8.~~7. Coordinate~~s~~ with Distribution Providers, Transmission Owners, Generator Owners and Load-Serving Entities in the evaluation and plans for all requests required to integrate new (~~E~~end-use ~~C~~customer, generation, and ~~t~~Transmission) ~~f~~Facilities into the BES~~ulk Electric System~~.

~~9.~~8. Submit~~s~~ and coordinate~~s~~ the plans for the interconnection of ~~f~~Facilities to the BES~~ulk Electric System~~ within its Transmission Planner area with other Transmission Planners and the Planning Coordinator~~Resource Planners~~, as appropriate.

~~10.~~9. Coordinate~~s~~ and develop~~s~~ ~~t~~Transfer ~~c~~Capability values with other Transmission Planners, Reliability Coordinators, Transmission Operators, Transmission Owners, ~~and~~ Transmission Service Providers, and the Planning Coordinator.

~~11.~~10. Coordinate~~s~~ with Transmission Owners and Generator Owners to define system protection and control needs and requirements, including ~~special protection systems (r~~Remedial ~~a~~Action ~~s~~Schemes~~),~~ to meet reliability needs.

11. Receive~~s~~ maintenance schedules and construction plans from Transmission Operator or Transmission Owner for input into and evaluation of BES~~ulk Electric System~~ expansion plans.

Resource Planning and Resource Planner

Resource Planning

Tasks

~~1. Consider generation capacity from resources both within and outside of the Resource Planner area for assessing resource adequacy.~~

~~2. Monitor and report, as appropriate, on its resource plan implementation.~~

~~3.~~1. ~~Develop and maintain resource (demand and capacity) models~~ Acquire or develop the tools needed to evaluate long-term resource ~~a~~Adequacy for a specific set of loads.

~~4.~~2. ~~Collect~~ Acquire or develop the data and information required for performing periodic resource ~~a~~Adequacy ~~purposes~~assessments.~~, including:~~

- ~~demand and energy forecasts, capacity resources, and demand response programs,~~
- ~~generator unit performance characteristics and capabilities, and~~
- ~~long-term capacity purchases and sales and~~
- ~~transmission (interface) limits.~~

3. Determine the reliability criteria used as the basis for assessing long-term resource Adequacy.

~~9.~~4. Perform periodic resource Adequacy assessments and document the results.

5. Evaluate future ~~, develop, document, and report on a~~ resource alternatives~~. adequacy plan for its portion of the Transmission Planner and Planning Coordinator area~~.

~~10.~~6. Create and periodically update a long-term resource plan~~Assist in the evaluation of the deliverability of resources~~.

Resource Planner

Definition

The ~~functional~~ entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority ~~Resource Planner~~ area.[10]

Relationships with Other Functional Entities

1. Collect data and information required for performing periodic resource Adequacy assessments from one or more of the following entities as necessary: Load-Serving Entity, Generator Owner, Generator Operator, Transmission Planner, Planning Coordinator, and Transmission Service Provider.

~~1.~~2. Provide long-term ~~Coordinates the~~ resource plan information ~~models with~~ to the ~~its~~ Transmission Planner for power system modeling and Planning Assessments~~Planning Coordinator~~.

~~2.~~3. Receive information from~~Coordinates with~~ the ~~Transmission Owners and~~ Transmission Planners regarding submitted resource plan ~~on the~~ deliverability ~~of resources to customers~~.

~~3.~~4. Provide resource plan recommendations to the affiliated ~~Coordinates with and collects data for resource planning from the Load-Serving Entities,~~ Generator Owner and Load-Serving Entity~~s, Generator Operators, Transmission Planners, Transmission Operators, Interchange Coordinators, and Reliability Assurers~~.

~~4.~~5. Coordinate~~s~~ with Transmission Planners~~,~~ and Transmission Service Providers~~, Reliability Coordinators, and Planning Coordinators~~ on resource ~~adequacy~~ plans.

~~5. Coordinates with adjoining Resource Planners within the Planning Coordinator area to avoid the double-counting of resources.~~

~~6. Reports its resource plan to the Transmission Planner and Planning Coordinator for evaluation and compliance with Reliability Standards.~~

~~7.~~6. Assess alternative ~~Works~~ plans with ~~the Planning Coordinator and~~ Transmission Planners to identify potential alternative ~~transmission~~ solutions to meet ~~Resource Planner~~resource Adequacy ~~plans~~requirements.

~~8. Applies methodologies and tools for the analysis and development of resource adequacy plans from the Planning Coordinator.~~

[10] Definition of Resource Planner from the NERC Glossary of Terms (as of May 15, 2016).

Reliability Operations and Reliability Coordinator

Reliability Operations

Tasks

1. Monitor all reliability-related parameters within the reliability area, including generation dispatch and ~~generation/transmission~~ maintenance plans for generation and Transmission.
2. Identify, communicate, and direct actions if necessary to relieve reliability threats and limit violations in the reliability area.
3. Develop Interconnection Reliability Operating Limits (to protect from instability and Cascading).
4. Assist in determining Interconnected Operations Services (IOS) ~~reliability-related services~~ requirements for:
    a. balancing generation and load,[11] and
    b. ~~transmission~~ reliability of Transmission ~~(*e.g.*, reactive requirements, location of operating reserves).~~
5. Perform reliability analysis (actual and ~~c~~Contingency) for the reliability area.
6. Direct revisions to ~~t~~Transmission maintenance plans as permitted by ~~a~~Agreements.
7. Direct revisions to generation maintenance plans as permitted by ~~a~~Agreements.
8. Direct implementation of emergency[12] procedures including load-shedding.
9. Direct and coordinate restoration of the BES for its RC Area~~system restoration~~.
10. Curtail Confirmed Interchange that adversely impacts reliability.
11. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

~~11.~~12. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[11] The Glossary definition of "Load" is not appropriate because the Glossary definition refers to end-use customer or end-use device; the Glossary definition does not incorporate the concept of quantity.
[12] The Glossary definition of "Emergency" is not appropriate because the definition is limited in application to the BES. In this context, the RC may encounter an emergency situation that is broader than the circumstances described in the Glossary definition.

Reliability Coordinator

Definition

~~The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.~~The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.[13]

Introduction to the Reliability Coordinator

The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator's ~~w~~Wide-~~a~~Area view. Wide-Area view means the entire Reliability Coordinator area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.[14] The ~~w~~Wide-~~a~~Area view includes situational awareness of its neighboring Reliability Coordinator Areas. ~~Its scope includes both transmission and balancing operations~~The RC ~~, and it~~ has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably. Its scope includes both:

1. **Transmission operations**. With respect to transmission operations, the Reliability Coordinator and Transmission Operator have similar roles, but different scopes. The Transmission Operator directly maintains reliability for its Transmission Operator Area~~own defined area~~. However, the Reliability Coordinator also maintains reliability, in concert with the other Reliability Coordinators, for the Interconnection as a whole. Thus, the Reliability Coordinator needs a ~~"w~~Wide-~~a~~Area~~"~~ view that reaches beyond its boundaries to enable it to operate within Interconnection Reliability Operating Limits. The Transmission Operator may or may not have this ~~"w~~Wide-~~a~~Area~~"~~ view, but the Reliability Coordinator does have it. The Reliability Coordinator may direct a Transmission Operator within its Reliability Coordinator Area to take whatever action is necessary to ensure that Interconnection Reliability Operating Limits are not exceeded.

2. **Balancing operations**. The Reliability Coordinator ensures that the generation-~~d~~Demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-~~d~~Demand-~~i~~Interchange balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance does not adversely impact reliability.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ with other Reliability Coordinators, Transmission Planners, and Transmission

[13] Definition of Reliability Coordinator from the NERC Glossary of Terms (as of May 15, 2016).
[14] Definition of "Wide-area" from the NERC Glossary of Terms (as of May 15, 2016).

Service Providers on ~~t~~Transmission system[15] limitations.

2. Receive~~s~~ facility[16] and operational data from Generator Operators, Distribution Providers, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.
3. Receive~~s~~ generation dispatch from Balancing Authorities and issue~~s~~ dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).
4. Receive~~s~~ integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.
5. Receive~~s~~ ~~t~~Transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.
6. ~~Develops~~Provide Interconnection Reliability Operating Limits (IROLs)~~, based on Transmission Owners' and Generator Owners' specified equipment ratings,~~ ~~and provides them~~ to those functional entities with a reliability-related need~~Transmission Operators~~.
7. Assist~~s~~ Transmission Operators in calculating and coordinating System Operating Limits.
8. Provide~~s~~ reliability analyses to Transmission Operators, Generator Operators and Balancing Authorities in its area as well as other Reliability Coordinators.
9. Direct~~s~~ Generator Owners and Transmission Owners to revise generation and ~~t~~Transmission maintenance plans that are adverse to reliability.
10. Receive~~s~~ balancing information from Balancing Authorities for monitoring.
11. Receive~~s~~ final approval or denial of Arranged Interchange from Interchange Coordinator.

~~12. Provide IROLs and TTC to the Transmission Service Provider for ATC calculation.~~

~~13.~~12. Develops operating agreements or procedures with Transmission Owners.

~~14.~~13. Coordinate~~s~~ with Transmission Operators on ~~system~~ restoration plans, contingency[17] plans and Interconnected Operations Services (IOS)~~reliability-related services~~.

Real-time

~~15.~~14. Coordinate~~s~~ reliability processes and actions with and among other Reliability Coordinators.

~~16.~~15. Receive~~s~~ Real-time operational information from Balancing Authorities, Interchange Coordinators and Transmission Operators for monitoring.

~~17.~~16. Issue~~s~~ reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange Coordinators, Regional Entities and NERC.

~~18.~~17. Issue~~s~~ corrective actions and ~~e~~Emergency procedure~~s~~ directives ~~(*e.g.*, curtailments or load shedding)~~ to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Coordinators.

[15] The Glossary definition of "System" is not appropriate in this context because the limitations may not always include a combination of generation, transmission, *and* distribution.

[16] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include non-BES elements (*e.g.*, industrial equipment).

[17] The Glossary definition of "Contingency" is not appropriate because application in this context is not limited to power system contingency (*i.e.*, N-1 event); in this context, intended to have broader meaning.

~~19.~~18. Specify~~ies~~ reliability–related requirements to Balancing Authorities.

~~20.~~19. Receive~~s~~ verification of ~~e~~Emergency procedures from Balancing Authorities.

~~21.~~20. Receive~~s~~ notification of Confirmed Interchange changes from Balancing Authorities.

~~22.~~21. Order~~s~~ re-dispatch of generation by Balancing Authorities.

~~23.~~22. Direct~~s~~ use of flow control devices by Transmission Operators.

~~24.~~23. Respond~~s~~ to requests from Transmission Operators to assist in mitigating equipment overloads.

Balancing and Balancing Authority

Balancing

Tasks

1. Control any of the following combinations within a Balancing Authority Area:
    a. ~~Load and generation (an isolated system)~~Demand and resource
    b. ~~Load~~ Demand and Confirmed Interchange
    c. Generation and Confirmed Interchange
    d. Generation, ~~load~~Demand, and Confirmed Interchange
2. Calculate ~~a~~Area ~~c~~Control ~~e~~Error (ACE) within the reliability area.
3. Operate in the Balancing Authority Area to maintain Demand and resource~~load-interchange-generation~~ balance.
4. Review generation commitments, dispatch, and ~~load~~ Demand forecasts.
5. Formulate an operational plan (*e.g.,* generation commitment, outages~~, etc.~~) for reliability evaluation.
6. Approve Arranged Interchange from ~~r~~Ramping ability perspective.
7. Implement Confirmed Arranged Interchange.
8. Operate the Balancing Authority Area to contribute to Interconnection frequency.
9. Monitor and report control performance and disturbance[18] recovery.
10. Provide balancing and energy accounting (including hourly checkout of Confirmed Arranged Interchange, Implemented Interchange and actual ~~i~~Interchange), and administer inadvertent energy paybacks.
11. Determine needs for Interconnected Operations Services~~reliability-related services~~.
12. Deploy Interconnected Operations Services (IOS)~~reliability-related services~~.
13. Implement ~~e~~Emergency procedures.
14. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
~~14.~~15. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[G] The Glossary definition of "Contingency" is not appropriate because the definition is too broad.

Balancing Authority

Definition

The ~~functional~~ responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports ~~contributes to~~ Interconnection frequency in real time.[19]

Relationships with Other Functional Entities

Ahead of Time

1. Receive generator Facility plans from Generator Operators within the Balancing Authority Area.
2. Receive operational data from Generator Operators within the Balancing Authority Area.
3. ~~1.~~ Receive~~s~~ operating and availability status of generating units ~~and operational plans and commitments~~ from Generator Operators ~~(including annual maintenance plans)~~ within the Balancing Authority Area.
4. ~~Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.~~
5. ~~3.~~ Receive~~s~~ reliability evaluations from the Reliability Coordinator.
6. ~~Receives final approval or denial of a request for an Arranged Interchange from the Interchange Coordinators.~~
7. Compile~~s~~ ~~load~~Demand forecasts from Load-Serving Entities.
8. Develop~~s~~ ~~a~~Agreements with adjacent Balancing Authorities for ACE calculation parameters.
9. Submit~~s~~ integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
10. ~~Confirms~~ Receive Arranged Interchange from~~with~~ Interchange Coordinators.
11. ~~Confirms~~ Send approval or denial of Arranged Interchange based on meeting ~~r~~Ramping requirements ~~capability~~ to ~~with~~ Interchange Coordinators.
12. ~~9.~~10. Receive notice of final approval or denial of Arranged Interchange becoming Confirmed Interchange from the Interchange Coordinator.
13. ~~10.~~11. Implement~~s~~ generator commitment and dispatch schedules from the Load-Serving Entities ~~and Generator Operators~~ who have arranged for ~~generation~~ resources within the Balancing Authority Area.
14. ~~11.~~12. Acquires Interconnected Operations Services (IOS) ~~reliability-related services~~ from Generator Operator.
15. ~~12.~~13. Receive~~s~~ dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
16. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
17. ~~13.~~15. Receive reports on frequency regulating equipment from Generator Operators within the Balancing Authority Area.

[19] Definition of Balancing Authority from the NERC Glossary of Terms (as of May 15, 2016).

~~14.~~16. Receive~~s~~ information from Load-~~-~~Serving Entities on self-provided Interconnected Operations Services (IOS) ~~reliability-related services~~.

~~15.~~17. Coordinate~~s~~ ~~system~~ restoration plans (*i.e.*, any combination of generation, Transmission or distribution components) with the Transmission Operator.

~~16.~~18. Provide~~s~~ ~~generation~~ resource dispatch to Reliability Coordinators.

Real-time

~~17.~~19. Coordinate~~s~~ use of Interruptible Demand ~~controllable loads~~ with Load-Serving Entities ~~(*i.e.*, interruptible load that has been bid in as a reliability-related service or has agreed to participate in voluntary load shedding program under resource/reserve deficiency situations)~~.

~~18.~~20. Receive~~s~~ loss allocation from Transmission Service Providers (for repayment with in-kind losses).

~~19.~~21. Receive~~s~~ Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.

~~20.~~22. Receive~~s~~ operating information from Generator Operators.

~~21.~~23. Provide~~s~~ Real-time operational information for Reliability Coordinator monitoring.

~~22.~~24. Receive~~s~~ reliability alerts from Reliability Coordinator.

~~23.~~25. Comply~~ies~~ with reliability-related requirements (*e.g.*, reactive requirements, location of operating reserves) specified by Reliability Coordinator.

~~24.~~26. Verify~~ies~~ implementation of ~~e~~Emergency procedures to Reliability Coordinator.

27. Inform~~s~~ Reliability Coordinator and Interchange Coordinators of Confirmed Interchange changes (*e.g.*, due to Demand ~~generation~~ or resource~~load~~ interruptions) involving its Balancing Authority Area.

~~25.~~28. Receive Confirmed Interchange revisions (including Curtailments) from Interchange Coordinators.

~~26.~~29. Direct~~s~~ resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in ~~r~~Real-~~-~~time.

~~27.~~30. Request ~~Directs~~ Transmission Operator (or Distribution Provider) to reduce voltage to lower Demand or shed load if needed to ensure balance within its Balancing Authority Area.

~~28.~~31. Direct~~s~~ Generator Operators to implement re-dispatch for congestion management as directed by the Reliability Coordinator.

~~29.~~32. Implements corrective actions and ~~e~~Emergency procedures as directed by the Reliability Coordinator.

~~30.~~33. Implement~~s~~ ~~system~~ restoration plans (*i.e.*, any combination of generation, Transmission or distribution components) as directed by the Transmission Operator.

~~31.~~34. Direct~~s~~ Transmission Operator to implement flow control devices.

~~31. Receives information of Implemented Interchange and Confirmed Interchange curtailments from Interchange Coordinator.~~

After the hour

~~32.~~35. Confirm~~s~~ Implemented Interchange with Confirmed Interchange provided by the Interchange Coordinators after the hour for "checkout."

36. Confirm~~s~~ Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities

after the hour for “checkout.”

~~33.~~37. Request record of individual Confirmed Interchange from Interchange Coordinator.

Market Operations and Market Operator (Resource Integrator)

Market Operations

Tasks

1. The m~~M~~arket ~~O~~operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability ~~F~~functions with commercial functions.

Market Operator (Resource Integrator)

Definition

The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.

Relationships with Other Functional Entities

Market oOperator tasks and relationships are specific to a particular market design and will depend on the market structure over which the ~~M~~market ~~O~~operator presides.

Transmission Operations and Transmission Operator

Transmission Operations

Tasks

1. Monitor and provide telemetry (as needed) of all reliability-related parameters within the reliability area.
2. Monitor the status of, and deploy, facilities[20] classed as ~~t~~Transmission assets, which may include the ~~t~~Transmission lines connecting a generating plant to the ~~t~~Transmission system, associated protective relaying systems and Remedial Action Schemes~~Special Protection Systems~~.
3. Develop ~~s~~System limitations (*e.g.*, ~~, such as~~ System Operating Limits) ~~and Total Transfer Capabilities,~~ and operate within those limits.
4. Develop and implement ~~e~~Emergency procedures.
5. Develop and implement ~~s~~System restoration plans.
6. Operate within established Interconnection Reliability Operating Limits.
7. Perform reliability analysis ~~(actual and contingency)~~ for the Transmission Operator Area.
8. Adjust Real Power, Reactive Power and voltage ~~flow control devices within the transmission area~~ to maintain reliability.

~~9. Deploy reactive resources to maintain transmission voltage within defined limits.~~

~~10.~~9. Determine the Transmission capability that supports the Reliable Operation of the Transmission Operator Area.

~~11.~~10. Operate or direct the operation of Transmission Facilities in its TOP Area.

11. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

12. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[20] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include responsibilities for non-BES elements.

Transmission Operator

Definition

The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.[21] ~~The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.~~

Introduction to the Transmission Operator

The Transmission Operator is responsible for the Real-time operating reliability of the ~~t~~Transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

The Transmission Operator and Reliability Coordinator have similar roles with respect to the reliability of the ~~t~~Transmission system~~operations~~, but have different responsibilities ~~scopes~~. The Transmission Operator shares a role in monitoring the Transmission system with ~~scope is narrower than~~ the Reliability Coordinator and additionally, has the operational responsibility for the Transmission system area under its purview.~~and the Transmission Operator does not necessarily "see" very far beyond its own boundaries. Therefore, t~~ The Transmission Operator can calculate System Operating Limits, but does not necessarily have the Wide-area view of the Reliability Coordinator ~~will not necessarily~~ necessary to calculate Interconnection Reliability Operating Limits.~~, which requires the wider scope of the Reliability Coordinator.~~

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ restoration plans with Reliability Coordinator, Transmission Operators, Balancing Authorities, and Distribution Providers.
2. Receive~~s~~ maintenance requirements and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receive~~s~~ Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receive~~s~~ reliability evaluations from the Reliability Coordinator.
5. Develop~~s~~ agreements (Operating Plans, procedures, and processes) with adjacent Transmission Operators ~~for joint transmission facilities~~.
6. Define~~s~~ Total Transfer Capabilities and System Operating Limits based on facility[22] information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator.
7. Arrange~~s~~ for Interconnected Operations Services (IOS) ~~reliability related services~~ from Generator Operators (*e.g.*, voltage schedules, VAR Demand schedule).
8. Develop~~s~~ contingency plans, and monitors operations of the ~~t~~Transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provide~~s~~ facility and operating information to the Reliability Coordinator.
10. Provide~~s~~ to the Transmission Planner information on the capability to ~~c~~Curtail (reduce) and shed load during ~~e~~Emergencies.

[21] Definition of Transmission Operator from the NERC Glossary of Terms (as of May 15, 2016).

[22] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include responsibilities for non-BES elements.

11. Provide~~s~~ Total Transfer Capabilities, ~~and~~ System Operating Limits, and methodology for calculating ~~to, and coordinates~~ Available Transfer Capability for respective Transmission paths to~~with,~~ Transmission Service Provider.

12. Receive~~s~~ operating and availability status of generating units from Generat~~or~~ion Operators including status of automatic voltage regulators and power system stabilizers.

~~12.~~13. Receive operational data from Generator Operators.

~~13.~~14. Develop~~s~~ operating agreements or procedures with Transmission Owners.

Real-time

~~14.~~15. Coordinates load shedding with, or as directed by, the Reliability Coordinator.

~~15.~~16. Provide~~s~~ Real-time operations information to the Reliability Coordinator and Balancing Authority.

~~16.~~17. Notify~~ies~~ Generator Operators of ~~t~~Transmission system problems (*e.g.*, voltage limitations or equipment overloads that may affect generator operations).

~~17.~~18. Request~~s~~ Reliability Coordinator to assist in mitigating equipment overloads. (*e.g.*, re-dispatch, ~~t~~Transmission loading relief).

~~18.~~19. Deploy~~s~~ reactive resources from Transmission Owners, ~~and~~ Generator Owners, and Distribution Providers ~~-~~to maintain acceptable voltage profiles.

~~19.~~20. Direct~~s~~ Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.

~~20.~~21. Implement~~s~~ flow control device operations for those ties under the Transmission Operator's purview as directed by the Balancing Authorities or Reliability Coordinator.

~~21.~~22. Receive~~s~~ reliability alerts from Reliability Coordinator.

~~22.~~23. Direct~~s~~ Balancing Authorities and Distribution Providers to implement system restoration plans.

~~23.~~24. Receive Real-time operating information from Generator Operators.

Interchange and Interchange Coordinator

Interchange

Tasks

1. Receive completed Request for Interchange (RFI) (*i.e.*, valid source and sink, Transmission arrangements) ~~an Arranged Interchange~~.
2. Transition RFI to ~~Ensure an~~ Arranged Interchange ~~is balanced and valid (Balancing Authority and Transmission Service Provider validation of sources and sinks, transmission arrangements, reliability-related services, etc.)~~.
3. Forward Arranged Interchange to entities for ~~Coordinate (*i.e.*, collect and consolidate)~~ approval, change, or~~and~~ denial ~~requests for an Arranged Interchange to become Confirmed Interchange~~. ~~Approvals may be explicit or by exception.~~
4. Collect approvals and denials ~~Receive confirmations~~ of requested Arranged Interchange.
5. Communicate status of an Arranged Interchange that becomes Confirmed Interchange or otherwise.
6. Communicate Confirmed Interchange information to the appropriate reliability assessment tools (*e.g.*, the interchange distribution calculator in the Eastern Interconnection).
7. Submit Arranged Interchange for Curtailments and re-dispatch implementation requests.

~~7.~~8. Maintain record of an individual Confirmed Interchange.

~~8.~~9. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

~~9.~~10. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Interchange Coordinator

Definition

The ~~functional~~ responsible entity that authorizes ~~ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates~~ implementation of valid and balanced Interchange Schedules ~~Confirmed Interchange~~ between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.[23]

Relationships with Other Functional Entities

Ahead of Time

1. Receive~~s~~ Requests for ~~Arranged~~ Interchange from Generation Owner, Purchasing-Selling Entity, and Load-~~-~~Serving Entit~~y~~ies~~s~~.
2. Submit~~s~~ ~~request for an~~ Arranged Interchange to become Confirmed Interchange to the Balancing Authorities and Transmission Service Providers for approvals.
3. Receive~~s~~ approval or denial from Transmission Service Providers of ~~t~~Transmission arrangement(s) for Arranged Interchange.
4. Receive~~s~~ approval or denial from Balancing Authorities of the ability to meet ~~r~~Ramping requirements for submitted Arranged Interchange.
5. Receives approval from Generation Owners, Purchase-Selling Entities, or Load-Serving Entities for any revised Arranged Interchange.
6. Communicate~~s~~ final approval or denial of a request for an Arranged Interchange to become Confirmed ~~i~~Interchange to the Reliability Coordinator, Balancing Authorities, Transmission Service Providers, Generation Owners, ~~and~~ Purchasing-Selling Entities, and Load-Serving Entities for implementation ~~and NERC identified reliability analysis services~~.

Real-time

7. Receive reliability alerts from the Reliability Coordinators.
8. Receive~~s~~ ~~c~~Curtailments and re-dispatch implementation requests from Reliability Coordinators and submits ~~for an~~ Arranged Interchange.
9. Receive~~s~~ information on Confirmed Interchange interruptions from the Balancing Authorities and communicates the Confirmed Interchange status to Balancing Authorities, Transmission Service Providers, Reliability Coordinators, Generation Owner, and Purchasing-Selling Entities, and ~~/~~Load- Serving Entities.
10. Inform~~s~~ Reliability Coordinators, Balancing Authorities, Transmission Service Providers, Generation Owners, Purchasing-Selling Entities, and~~/~~ Load-Serving Entities~~, Reliability Coordinators, and Balancing Authorities~~ of Confirmed Interchange revisions (including ~~c~~Curtailments).

After the hour

11. ~~Maintains and p~~Provide~~s~~ a record of individual Confirmed Interchange to requesting ~~for which it coordinated with the~~ Balancing Authorities.

[23] Definition of Interchange Authority from the NERC Glossary of Terms (as of May 15, 2016). The Glossary uses the term "Interchange Authority" whereas the Functional Model uses the term "Interchange Coordinator."

12. Coordinate~~s~~ Confirmed Interchange with Balancing Authorities after the hour for "checkout."

Transmission Service and Transmission Service Provider

Transmission Service

Tasks

1. Receive ~~t~~Transmission ~~s~~Service requests and process each request for service according to the requirements of the tariff.
    a. Maintain commercial interface for receiving and confirming requests for ~~t~~Transmission ~~s~~Service according to the requirements of the tariff (*e.g.*, OASIS).
2. Determine and post available transfer ~~capability~~ capacity values.
3. Approve or deny ~~t~~Transmission ~~s~~Service requests.
4. Approve or deny Arranged Interchange from ~~t~~Transmission ~~s~~Service arrangement perspective.
5. Allocate ~~t~~Transmission losses (MWs or funds) among Balancing Authority Areas.
6. Acquire Ancillary Services to support Transmission Service.
~~5.~~7. Update information that is relevant to a long-term Transmission Service arrangement.

Transmission Service Provider

Definition

The ~~functional~~ entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable ~~t~~Transmission ~~s~~Service agreements.[24]

Relationships with Other Functional Entities

Ahead of Time

1. Receive the methodology to determine available transfer capacity from the Transmission Operator.

~~1.~~2. Receive~~s~~ Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from ~~Planning Coordinator,~~ the Transmission Planner~~,~~ Transmission Operator and Reliability Coordinator, and coordinates ~~A~~available ~~T~~transfer capacity~~Capability~~ with these entities and other Transmission Service Providers.

~~2. Receives transmission Facility Ratings from Transmission Owners.~~

3. Receive~~s~~ ~~t~~Transmission expansion plans identified by the Transmission Planner(s) ~~Planning Coordinator~~ to help determine ability to accommodate long-term ~~t~~Transmission ~~s~~Service requests.

4. Arrange for providers of Ancillary Services, and notify the Transmission Operator and Balancing Authority.

5. ~~Approves~~ Accept or ~~denies~~ decline ~~t~~Transmission ~~s~~Service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.

~~6. Confirms validity of transmission service requests indicated in the Arranged Interchange with Interchange Coordinators.~~

~~7.~~6. Develop~~s~~ ~~a~~Agreements or procedures with Transmission Owners.

7. Receive~~s~~ ~~final approval or denial of~~ Arranged Interchange from Interchange Coordinator.

8. Send approval or denial of Arranged Interchange to Interchange Coordinator based on meeting Transmission Service arrangements.

9. Receive notice of final approval or denial of Arranged Interchange becoming Confirmed Interchange from Interchange Coordinator.

10. Receives updated information from Balancing Authority, Resource Planner, Load-Serving Entity, Purchasing-Selling Entity, and market operator for long-term Transmission Service arrangement.

Real-time

~~8.~~11. Receive~~s~~ Confirmed Interchange revisions ~~implementation~~ (including ~~c~~Curtailments) from the Interchange Coordinators.

12. Receive Confirmed Interchange Interruption status from Interchange Coordinator.

~~9.~~13. Receive~~s~~ reliability alerts from Reliability Coordinator.

14. Provide~~s~~ loss allocation to Balancing Authorities.

[24] Definition of Transmission Service Provider from the NERC Glossary of Terms (as of May 15, 2016).

15. Notify the Transmission Operator and Balancing Authority of changes to Ancillary Services.

Transmission Ownership and Transmission Owner

Transmission Ownership

Tasks

1. Develop interconnection ~~a~~Agreements.
2. Establish ~~r~~Ratings of ~~t~~Transmission facilities.~~-~~[25]
3. Maintain ~~t~~Transmission facilities and rights-of-way.
4. Design and install owned facilities classified as ~~t~~Transmission and obtain associated rights-of-way.
5. Design and authorize maintenance of ~~t~~Transmission protective relaying systems and ~~Special Protection Systems~~Remedial Action Schemes.
6. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
7. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

[25] The Glossary definition of "Facility" is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application for non-BES elements.

Transmission Owner

Definition

The ~~functional~~ entity that owns and maintains transmission ~~f~~Facilities.[26]

Relationships with Other Functional Entities

1. Coordinate~~s~~ with Transmission Planners, ~~and~~ the Planning Coordinator, ~~Generator Owners,~~ and other Transmission Owners, ~~and Load-Serving Entities~~ desiring to connect with the Transmission system under the purview of the Transmission Owner. ~~the Bulk Electric System.~~
2. Receive~~s~~ approved ~~t~~Transmission expansion plans from the Transmission Planner.
3. Develop~~s~~ agreements or procedures with the Transmission Service Providers.
4. Develop~~s~~ operating agreements or procedures with the Transmission Operators, Reliability Coordinators and Distribution Providers.
5. Develop~~s~~ agreements with adjacent Transmission Owners for joint ~~t~~Transmission facilities.
6. Provide~~s~~ ~~t~~Transmission expansion plans and changes to the Planning Coordinator and Transmission Planners.
7. Provide~~s~~ ~~t~~Transmission Facility Ratings to Transmission Operators, Reliability Coordinators, Transmission Service Providers, Distribution Providers, Transmission Planners, and Planning Coordinator.
8. Provide~~s~~ maintenance and construction plans and schedules to the Reliability Coordinator, Transmission Operator, and Transmission Planner.
9. Coordinate and ~~D~~develop~~s~~ interconnection agreements with the Distribution Providers, ~~and~~ Generation Owners, and Load Serving Entities desiring to connect with the Transmission system under the purview of the Transmission Owner ~~for connecting to the Bulk Electric System~~.
10. Provide~~s~~ reactive resources to Transmission Operators.
11. Revise~~s~~ ~~t~~Transmission maintenance plans as requested by a Transmission Operator or the Reliability Coordinator.

[26] Definition of Transmission Owner from the NERC Glossary of Terms (as of May 15, 2016).

Distribution and Distribution Provider

Distribution

Tasks

1. Provide and operate electrical delivery ~~f~~Facilities between the ~~t~~Transmission system and the ~~E~~end-use ~~C~~customer or distribution-connected energy resource.
2. Identify and characterize its connected load and energy resources.
3. ~~2.~~Implement voltage reduction.
4. ~~3.~~Design and maintain protective relaying systems, under-frequency load-shedding systems, under-voltage load-shedding systems, and Remedial Action Schemes~~Special Protection Systems~~ that interface with the ~~t~~Transmission system.
5. ~~4.~~Provide and implement load-shed capability.
6. ~~5.~~Maintain voltage and power factor within specified limits at the interconnection point.
7. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
8. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Distribution Provider

Definition

The functional entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.[27] ~~The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.~~

Introduction to the Distribution Provider

The Distribution Provider delivers ~~e~~Electrical ~~e~~Energy ~~to the End-use Customer~~ from the ~~t~~Transmission system to the ~~E~~end-use ~~C~~customer. ~~For those End-use Customers who are served at transmission voltages, the Transmission Owner may also serve as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.~~ The Distribution Provider provides the switches and re-closers that could be used to shed load for ~~e~~Emergency action.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate~~s~~ with Transmission Planners on interconnected load and energy resources to support ~~t~~Transmission analysis~~expansion~~.
2. Coordinate~~s~~ ~~s~~System restoration plans with Transmission Operator.
3. Coordinate~~s~~ with ~~E~~end-use ~~C~~customers, distributed energy resources, and Load-Serving Entities to identify new ~~f~~Facility connection needs.
4. Develop interconnection agreements with Transmission Owners on a ~~f~~Facility basis.
5. Provide~~s~~ operational data to Transmission Operator.
6. Coordinate with Load-Serving Entities to identify critical loads that are to be precluded from load-shedding where avoidable.
7. Provide protective relaying systems, under-frequency load-shedding systems, under-voltage load-shedding systems, and Remedial Action Schemes as defined by the Transmission Planner and Planning Coordinator.

Real-time

8. Obtain voltage and power factor requirements from the Transmission Operator.

~~6.~~9. Implement~~s~~ voltage reduction and shed~~s~~ load as directed by the Transmission Operator or Balancing Authority.

~~7.~~10. Implement~~s~~ ~~s~~System restoration plans as coordinated by the Transmission Operator.

~~8.~~11. Direct~~s~~ Load-Serving Entities to communicate requests for voluntary load ~~c~~Curtailment.

[27] Definition of Distribution Provider from the NERC Glossary of Terms (as of May 15, 2016).

Generator Operation and Generator Operator

Generator Operation

Tasks

1. Formulate daily generation plan.
2. Report operating and availability status of generator Facility(ies) ~~units~~ and related equipment, such as automatic voltage regulator~~s~~ equipment, power system stabilizer equipment and frequency regulating equipment.
3. Operate generator~~s~~ Facility(ies) to provide ~~r~~Real Power and ~~r~~Reactive ~~p~~Power or Interconnected Operations Services ~~reliability-related services~~ in accordance with ~~per~~ contracts or arrangements.
4. Monitor the status of generator~~ing~~ ~~f~~Facility(ies).
5. Support Interconnection frequency and voltage.
6. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
7. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Generator Operator

Definition

The ~~functional~~ entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services~~reliability related services~~.[28]

Relationships with Other Functional Entities

Ahead of Time

1. Provide~~s~~ generation commitment plans to the Balancing Authority.
2. Provide~~s~~ Balancing Authority and Transmission Operators with requested amount of Interconnected Operations Services (IOS)~~reliability-related services~~.
3. Provide~~s~~ availability and operating ~~and availability~~ status of generator~~ing~~ ~~units~~ Facility(ies), to Reliability Coordinator, Balancing Authority and Transmission Operators for reliability analysis.
4. Report~~s~~ status of automatic voltage regulating equipment and power system stabilizer equipment ~~or frequency regulating equipment to~~ Transmission Operators.
5. Report on frequency regulating equipment to Balancing Authority.
6. Provide~~s~~ operational data to Reliability Coordinator, Balancing Authority and Transmission Operator.
7. ~~Receives reliability analyses from Reliability Coordinator.~~
8. Receive~~s~~ notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.
9. Receive~~s~~ reliability alerts from Reliability Coordinator.
10. Receive~~s~~ notification of ~~t~~Transmission system problems from Transmission Operators.

Real-time

11. Provide~~s~~ Real-time operating information to the Transmission Operators and the required Balancing Authority.
12. Adjust~~s~~ ~~r~~Real Power and ~~r~~Reactive ~~p~~Power as directed by the Balancing Authority and Transmission Operators.

[28] Definition of Generator Operator from the NERC Glossary of Terms (as of May 15, 2016).

Generator Ownership and Generator Owner

Generator Ownership

Tasks

1. Establishes generatiorng facilities Facility rRatings, limits, and operating requirements.
2. Designs and authorizes maintenance of the generatiorn plant protective relaying systems, protective relaying systems on the tTransmission lines connecting the generatiorn plant to the tTransmission system, and Remedial Action Schemes (RAS)Special Protection Systems related to the generator.
3. Performs or authorizes Maintains maintenance of owned generatoring fFacilities.
4. Provides verified generatiorng fFacility performance characteristics / data.
5. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
6. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Generator Owner

Definition

The ~~functional~~ entity that owns and maintains generating Facility(ies)~~units~~.[29]

Relationships with Other Functional Entities

Ahead of Time

1. Provide~~s~~ generator Facility(ies) information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner.
2. Provide~~s~~ generator Facility(ies) ~~unit~~ maintenance schedules and generator Facility(ies) ~~unit~~ retirement plans to the Reliability Coordinator, Transmission Operator, Balancing Authority, Transmission Planner, and Resource Planner.
3. Develop~~s~~ ~~an~~ interconnection ~~a~~Agreement(s) with Transmission Owner on a ~~f~~Facility basis.
4. Receive~~s~~ approval or denial of ~~t~~Transmission ~~s~~Service request from Transmission Service Provider.
5. Provide~~s~~ Interconnected Operations Services ~~reliability related services~~ to Purchasing-Selling Entity pursuant to agreement.

~~6. Reports the annual maintenance plan to the Reliability Coordinator, Balancing Authority and Transmission Operator.~~

6. Revise~~s~~ the generator~~ion~~ maintenance plans as requested by the Balancing Authority, Transmission Operator, and Reliability Coordinator.
7. Submit Request for Interchange to the Interchange Coordinator.
8. Submit approval for original or revised Arranged Interchange to the Interchange Coordinator.
~~7.~~9. Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.

Real-time

10. Receive Confirmed Interchange Interruptions status from the Interchange Coordinator.
~~8.~~11. Receive Confirmed Interchange revisions (including Curtailments) from the Interchange Coordinator.

[29] Definition of Generator Owner from the NERC Glossary of Terms (as of May 15, 2016).

Purchasinge-Selling and Purchasinge-Selling Entity

Purchasinge-Selling

Tasks

1. Purchase and sell energy or capacity.
2. Arrange for ~~t~~Transmission ~~s~~Service that is required to implement an Interchange Transaction~~by tariffs~~.
3. Request implementation of Arranged Interchange.

Purchasinge-Selling Entity

Definition

The ~~functional~~ entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services~~reliability related services~~. Purchase-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.[30]

Relationships with Other Functional Entities

Ahead of Time

1. Arrange for energy and capacity from Generator Owners.
2. Arrange~~s~~ for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for self-provided Interconnected Operations Services ~~reliability-related services~~ with Generator Owners or Load-Serving Entities.
3. Submit~~s~~ Requests For Interchange to Interchange Coordinators.

~~3.~~4. Submit approval for original or revised Arranged Interchange to Interchange Coordinator.

~~4. Notifies Generator Operators and Load-Serving Entities if Arranged Interchange requests are approved or denied.~~

5. Receive~~s~~ communication that ~~final approval or denial of~~ Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.
6. Receive~~s~~ ~~load~~ Demand profiles and forecasts from Load-Serving Entities.

Real-time

7. Receive notice of Confirmed Interchange Interruptions from Interchange Coordinator.
8. Receive notice of Confirmed Interchange revisions (including Curtailments) from Interchange Coordinator.

~~7.~~9. Notify~~ies~~ Interchange Coordinators of Confirmed Interchange and Implemented Interchange cancellations or terminations.

~~8.~~10. Receive~~s~~ notice of Confirmed Interchange ~~c~~Curtailments from Interchange Coordinator.

[30] Definition of Purchasing-Selling Entity from the NERC Glossary of Terms (as of May 15, 2016).

Load-Serving and Load-Serving Entity

Load-Serving

Tasks

1. Collect individual load profiles and characteristics.
2. Identify capability for and communicate requests for voluntary load ~~c~~Curtailment.
3. Identify and communicate ~~Participate in under-frequency load shedding systems and under-voltage load shedding systems through identification of~~ critical customer loads that are to be excluded from the load-shedding systems.
4. Identify the resources needed for ~~facilities and provide capability of~~ self-provided Interconnected Operations Services (IOS) ~~reliability-related services for its load~~.
5. Develop overall load profiles and forecasts of end-user energy requirements.
6. Acquire necessary ~~t~~Transmission ~~s~~Service, and provide for Interconnected Operations Services~~reliability-related services~~.
7. Arrange for ~~Submits Requests For~~ Interchange ~~to Interchange Coordinators.~~
8. Manage resource portfolios to meet ~~demand~~ Demand and energy delivery requirements. ~~of End-use Customers.~~

Load-Serving Entity

Definition

~~The functional entity that~~ ~~secures~~ Secures energy and ~~t~~Transmission ~~s~~Service (and Interconnected Operations Services)~~reliability related services)~~ to serve the electrical demand and energy requirements of its end~~-~~use customers.[31]

Relationships with Other Functional Entities

Ahead of Time

1. Submit~~s~~ load data ~~profiles and characteristics, plans, and forecasts~~ as needed to the appropriate entity (*e.g.,* ~~-~~Balancing Authorities, ~~Purchasing-Selling Entities, Planning Coordinator,~~ and Resource Planners, and Transmission ~~Planners~~Service Provider) in accordance with applicable tariffs, interconnection agreements or other arrangements.
2. Coordinate with Distribution Provider to identify critical loads that are to be excluded from load-shedding. ~~Identifies new facility connection needs for End-use Customers.~~
3. Provides generation commitments and dispatch schedules to the Balancing Authority.
4. Provide~~s~~ information regarding~~as to~~ self-provided Interconnected Operations Services (IOS) ~~reliability-related services~~ to the Balancing Authority.
5. Provide~~s~~ necessary data ~~planned purchases~~ to the Resource Planner and Transmission Planner for ~~s~~System modeling and reliability evaluation.
6. Arrange~~s~~ for ~~t~~Transmission ~~s~~Service from Transmission Service Providers and makes arrangements for Ancillary Services ~~reliability-related services~~ with Generator Owners or Load-Serving Entities.
7. Submit~~s~~ Requests For Interchange to Interchange Coordinator~~s~~.

~~7.~~8. Submit approval for original or revised Arranged Interchange to Interchange Coordinator.

9. Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.

~~8.~~10. Notify~~ies~~ Generator Operators if Arranged Interchange requests are approved or denied.

~~9. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.~~

~~10.~~11. Coordinate~~s~~ with Distribution Provider on identifying new ~~f~~Facility interconnection needs.

~~10. Receives notification from Purchasing-Selling Entity if Arranged Interchange requests approved or denied.~~

Real-time

~~11.~~12. Receive~~s~~ requests from the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider ~~-~~for voluntary load ~~c~~Curtailment.

~~12.~~13. Communicate requests for voluntary load ~~c~~Curtailment to end-use customers as directed by the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider.

[31] Definition of Load-Serving Entity from the NERC Glossary of Terms (as of May 15, 2016).

~~13. Notifies Interchange Coordinators of Confirmed Interchange cancellations or terminations.~~

14. Receive~~s~~ notice of Confirmed Interchange revisions (including ~~c~~Curtailments) from Interchange Coordinator.

~~14.~~15. Receive notice of Confirmed Interchange Interruptions from Interchange Coordinator.

Section IV: Version History

[This section will be completed prior to seeking final approval from the Standards Committee.]

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Functional Model Technical Document

Version 6~~5~~

Prepared by the Functional Model Advisory Group
Approved by the Standards Committee: [Month, Year]

RELIABILITY | ACCOUNTABILITY






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Introduction

The Functional Model Technical Document (FMTD) ~~This document~~ is intended as a companion to Version ~~5~~ 6 of the Functional Model to help explain the functions, including the functional entities, the respective tasks performed by each functional entity, and the relationships with other functional entities that are necessary to perform the tasks. ~~the reader better understand the Model's Functions, functional entities and their relationships. This document therefore provides context, explanation and opinions. It is a companion to, rather than a formal part of, Version 5 of the Model.~~

Section I – Functional Entity Tasks and Interrelationships provides details regarding the functional entity tasks and interrelationships. ~~about each of the Responsible Entities.~~ A number of the ~~Some~~ functional entities, such as the Transmission Owner or Purchasing-Selling Entity, are adequately described in the FM~~unctional Model document~~, so~~and~~ there is no need to provide further ~~little~~ detail in the FMTD~~to add here~~. Other entities, such as the Interchange Coordinator and Balancing Authority, are more complex, including their ~~both unto themselves and in their~~ relationships with other functional entities, and the FMTD ~~is document~~ provides further explanation regarding how these entities work together to ensure reliability~~additional explanations~~.

Section II – Technical Discussion includes technical discussions on related topics such as managing Arranged and Confirmed Interchange, and functional entity areas and boundaries~~y conditions~~. ~~The discussion of Market Operations illustrates that the Model applies to different market structures.~~

SECTION I – FUNCTIONAL ENTITY TASKS AND INTERRELATIONSHIPS

~~Version 4 of the Model, issued in 2008, clarified the concept of responsibility in the Model, as reflected in the use of the term Responsible Entity. In particular, it was clarified that while there were responsibilities of the entities in the Functional Model within the context of the Model itself, the responsibilities that will actually apply to an organization will be determined within NERC's registration, certification and compliance processes and Reliability Standards, not by the Model.~~

~~However, it subsequently became apparent to the Functional Model Working Group that having two different contexts for responsibility did not completely eliminate the potential for confusion. On this basis, Version 5 goes one step further and eliminates reference to responsibility within the Model, replacing the term responsible entity with the term functional entity. In Version 5 of the Model, an entity is defined by the functions it performs.[1]~~

~~As a result of refocusing the Model on Tasks rather than responsibility, Version 5 of the Technical Document has removed discussions associated with responsibility of individual organizations. These matters are now addressed within the context of NERC's registration and compliance programs, typically within the NERC Rules of Procedure. These include situations where:~~

- ~~an organizations may "bundle" a number of different functions and register as the corresponding functional entities, for example Reliability Coordinator and Transmission Operator~~
- ~~two or more organizations may register jointly with NERC as functional entities and thereby divide or share responsibility for meeting standards requirements (Joint Registry Organizations)~~
- ~~an organization may register and assume responsibility for Tasks performed by others, such as a rural cooperative on behalf of its members.~~

~~[1] Version 5 of the Model uses the term "functional entity" to apply to the *entity described in the Functional Model* (Balancing Authority, etc). It is proposed that other NERC documents follow this usage, and also that they use the terms "registered entity", "certified entity" and "responsible entity", in reference to *specific organizations*. For example, PJM is a registered entity and certified entity for the Balancing Authority functional entity.~~

Part 1 - Reliability Coordinator

The Reliability Coordinator~~'s~~ purview must be broad enough to enable it to ~~calculate~~ establish Interconnection Reliability Operating Limits, which will involve ~~s~~System and facility operating parameters beyond its own Area as well as within it. This is in contrast to the Transmission Operator, which also maintains reliability, but is directly concerned with system parameters within its own Area.

The Reliability Coordinator is the highest operating authority; the underlying premise is that reliability of a wide-area takes precedence over reliability of any single local area. Only the Reliability Coordinator has the perspective/vision necessary to act in the interest of wide-area reliability.

The Reliability Coordinator also assists the Transmission Operator in monitoring for and relieving equipment or facility overloads through transmission loading relief measures if market-based dispatch procedures are not effective.

Role in Interchange. The Reliability Coordinator does not receive tags, but may curtail Interchange Transactions until they are arranged and ready for implementation as Interchange Schedules. As such, it does not approve or deny tags. However, once the Reliability Coordinator receives the Interchange Schedule information, it will have the necessary information to aid its assessment of the impacts of flowing and impending Transaction Schedules on its area's reliability. As necessary, the Reliability Coordinator may issue transmission loading relief requests (or similar requests for congestion management) which may result in reducing, removing or halting flowing or impending Interchange Transactions. This is viewed by some as "denying" the Interchange Transactions although in this context, the "denial" is not provided during the collection of approval stage.

Day-ahead analysis. The Reliability Coordinator will receive the dispatch plans from the Balancing Authority(ies) on a day-ahead basis. The Reliability Coordinator will then analyze the dispatch from a transmission reliability perspective. If the Reliability Coordinator determines that the Balancing Authority's dispatch plans will jeopardize transmission reliability, the Reliability Coordinator will work with the Balancing Authority to determine where the dispatch plans need to be adjusted. The Reliability Coordinator obtains generation and transmission maintenance schedules from Generator Operators and Transmission Operators. The Reliability Coordinator has final authority in coordination and resolution of conflicts regarding transmission and generation outage requests. The Reliability Coordinator can deny a transmission outage request and some elective, generation outage requests if a transmission system reliability constraint would be violated.

The Transmission Operator is responsible for the reliability of its "local" transmission system in accordance with establishing and maintaining System Operating Limits (SOLs).However, in some circumstances, as noted above for reliability analysis associated with generation dispatch instructions, the Reliability Coordinator may become aware of a potential SOL ~~violation~~ exceedance and issue a dispatch adjustment. Therefore, in this context, the Reliability Coordinator also has a role regarding the Transmission Operator's management of SOL exceedances.

Emergency actions. The Reliability Coordinator is responsible for Real-time system reliability, which includes calling for the following emergency actions:

- Curtailing Interchange Schedules
- Directing re-dispatch to alleviate congestion or other SOL exceedances

- Mitigating energy and transmission emergencies
- Ensuring energy balance and Interconnection frequency
- Directing load shedding.

The Reliability Coordinator, in collaboration with the Balancing Authority and Transmission Operator, can invoke public appeals, voltage reductions, ~~d~~Demand-~~s~~Side ~~m~~Management, Energy Emergency alerts, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.

System restoration actions. The Reliability Coordinator directs and coordinates ~~system~~ restoration of the BES for its RC Area, with Transmission Operators, ~~and~~ Balancing Authorities and other Reliability Coordinators.

~~**Authority to perform its reliability functions**. The Reliability Coordinator's authority is documented in one or more regional reliability plans, as applicable, for the Region in which the Reliability Coordinator Area is located. In cases where a Reliability Coordinator Area spreads over multiple Regions, its authority will be documented in and accepted by all the concerned Regions through their respective reliability plans.~~

In addition, since the Reliability Coordinator may also have a role regarding the Transmission Operator's management of SOL exceedances, delineation of its authority and that of the Transmission Operator needs to be clearly defined ~~in the reliability plan(s)~~.

Part 2 - Balancing Authority

The Balancing Authority operates within the metered boundaries that establish the Balancing Authority Area. Every generator, ~~t~~Transmission ~~f~~Facility, and end-use customer is in a Balancing Authority Area. The Balancing Authority's mission is to maintain the balance between ~~loads~~ Demand and resources in real time within its Balancing Authority Area by keeping its actual ~~i~~Interchange equal to its scheduled ~~i~~Interchange and meeting its ~~f~~Frequency ~~b~~Bias obligation. The demand~~load~~-resource balance is measured by the Balancing Authority's Area Control Error (ACE). In performing its balancing function, the Balancing Authority does not own the resources.

~~NERC's Reliability Standards require that t~~The Balancing Authority maintains its ACE within acceptable limits. Maintaining ~~resource-d~~Demand-resource balance within the Balancing Authority Area requires four types of resource management, all of which are the Balancing Authority's responsibility. Each of these resource management functions require sufficient resources provided to it by other entities:

- ~~F~~frequency control through tie-line bias
- Regulation ~~s~~Service deployment
- ~~L~~load-following through economic dispatch
- Interchange implementation

Frequency control through ~~t~~Tie-~~l~~Line ~~b~~Bias. To maintain frequency within acceptable limits, the Balancing Authority controls resources within its Balancing Authority Area to meet its ~~f~~Frequency ~~b~~Bias obligation to the ~~i~~Interconnection.

Regulation service deployment. To maintain its ACE within these acceptable limits, the Balancing Authority controls a set of generators within its Balancing Authority Area that are capable of providing ~~r~~Regulation ~~s~~Service.

Load-following through economic dispatch. The organization that serves as the Balancing Authority will in general also perform unit commitment and economic dispatch; however, in some markets, Generator Operators may be permitted to perform unit commitment and economic dispatch among the fleet of generators under their control and within the requirements accepted by the market operator.

Interchange implementation. The Balancing Authority receives Confirmed Interchange from one or more Interchange Coordinators, and enters those Interchange Schedules into its energy management system.

Unit commitment and schedules from Load-Serving Entities. The Balancing Authority receives resource dispatch plans from the Market Operator and/or unit commitment and dispatch ~~s~~Schedules from the Load-Serving Entities that have bilateral arrangements for generation within the market or the Balancing Authority Area. The Balancing Authority provides this commitment and dispatch ~~s~~Schedule to the Reliability Coordinator.

Role in approving Interchange. The Balancing Authority approves an Arranged Interchange with respect to the ramping requirements of the generation that must increase or decrease to implement the Interchange. The Balancing Authority provides its approval or denial to the Interchange Coordinator.

Energy Emergencies. In the event of an Energy Emergency, the Balancing Authority can implement public appeals, ~~d~~Demand-~~s~~Side ~~m~~Management programs, and, ultimately load shedding. Obviously, it must do this in concert with the Reliability Coordinator.

Failure to balance. The Balancing Authority must take action, either under its own initiative or direction by the Reliability Coordinator, if the Balancing Authority cannot comply with NERC's Reliability Standards regarding frequency control and Area Control Error.

~~See "Managing Bilateral Interchange Transactions"~~

Reserve Sharing Groups: In the past, only reserve sharing groups have been associated with Contingency Reserve. However, as the industry has evolved, additional commercial relationships between Balancing Authorities are occurring and thus creating new responsible groups. These responsible groups now include Regulation Reserve Sharing Groups, Frequency Response Sharing Groups, Frequency Response Sharing Groups and Contingency Reserve Sharing Groups. These groups are the responsible entities, but the Balancing Authorities remain responsible for performance within each respective group. The Balancing Authorities enter into commercial arrangements among themselves to form the respective sharing groups.

Part 3 - Planning Coordinator

The Planning Coordinator coordinates and integrates ~~t~~Transmission facility and service plans, resource plans, and protection system plans among the Transmission Planner(s) ~~and Resource Planner(s)~~ within its area of purview. These activities range from review and ~~integration~~ assessing~~of~~ expansion ~~reinforcement~~ and corrective action plans developed by the Transmission Planner(s) ~~functional entities whose area of responsibility is~~ within the Planning Coordinator's area ~~with respect to established reliability needs to providing procedures, protocols, modeling and methodology software, etc. for consistent use within its area~~. The assessment should consider the interaction of system changes under a range of selected scenarios across the entire Planning Coordinator area. The PC assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one Transmission Planner; however, the area under the purview of a Planning Coordinator may include as few as one Transmission Planner. The Planning Coordinator's scope of activities is intended to span a broader area that may include BES assets of multiple Transmission Planners. All BES Facilities should be assigned to a Transmission Planner and to a Planning Coordinator, so that there are no gaps in the assessment of the BES.

Planning Coordinators work through a variety of processes to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all portions of the interconnected BES are completely coordinated for planning activities. While much of what the Planning Coordinator performs could be actually performed by a Transmission Planner, such as developing methodologies in conjunction with surrounding Transmission Planners, recognition of resource plans, assessing system performance consistent with reliability needs by itself, and collaborating with other Transmission Planners to assess impacts on the interconnected area, the Planning Coordinator by its very nature will generally take responsibility over a wider perspective than the Transmission Planners for which its coordinates. The Planning Coordinator generally conducts system performance assessments, in collaboration with other Planning Coordinators to consider transfer/flows across multiple Transmission Planner areas or intra- and inter- state areas such as generation dispatch scenarios caused by temperature or fuel extremes. Geographic size is not necessarily a critical consideration, it is the extent and impact of the electrical network that the planners have taken responsibility for assessing that determines whether an area is large enough for analysis and planning

~~Although the Functional Model sets forth the concept of the Planning Coordinator and how a functional entity could perform as such, there may be situations or circumstances under actual organizational structures whereby a single entity does not exist that performs the Reliability Planning Function but rather the function is taken on by a number of entities, *e.g.*, a group of Transmission Planners, or an organization such as a regional group formed within a region or possibly the Regional Entity itself. In all these cases the Reliability Planning Function is still performed in some manner by some entity or organization.~~

The boundaries for the Planning Coordinator area are basically defined by the location of the Bulk Electric System facilities under the purview of the Planning Coordinator, *i.e.* those facilities for which the Planning Coordinator coordinates and evaluates and recommends reinforcement and corrective plans resulting from studies and analysis of system performance and interconnection of facilities. The BES facilities under its purview, are generally contiguous and cover in aggregate the same areas as the Transmission Planners its coordinates. Traditionally transmission planning has been associated with one or more Transmission Owners, *i.e.* reinforcement and corrective action plans must be associated with certain Transmission Owner facilities. Since transmission ownership may cross state or provincial or regional boundaries, the BES ~~f~~Facilities on one side of the Transmission Owner boundary may be in one Planning Coordinator area

whereas the remaining facilities may be in another. As such the Planning Coordinator area is not constrained to fit within a Reliability Coordinator or Transmission Operator Area. However, the Planning Coordinator area must cover at least one Transmission Planner Area. ~~and one Resource Planner area, or part thereof if either or both of these planner areas is larger than the Planning Coordinator area. On the other hand, there is the possibility that a Planning Coordinator area could be nested inside an even larger Planning Coordinator area provided the smaller Planning Coordinator does in fact perform the appropriate system assessments. In this special case, the larger Planning Coordinator would perform the ultimate planning coordinating function for all the Resource Planners, Transmission Planner and smaller Planning Coordinator in its Area. As an example, some ISOs and RTOs perform the Reliability Planning Functions but they are also under the purview of the Regional Entity that also performs the Reliability Planning Functions at a broader scale.~~

In many areas, there may exist more than one Transmission Planner ~~and Resource Planner, as well as a nested Planning Coordinator, within a Planning Coordinator area,~~ each performing a different role demarcated primarily by their particular function and scale (area-wise) of assessments performed. In order to ensure all BES Facilities are associated with a Planning Coordinator, clear delineation of the "PC Area" should establish the BES Facilities and associated connections to its adjacent Planning Coordinators. ~~In these cases, delineation of the role of the various functional entities needs to be clearly defined in the regional reliability plan(s).~~

The Planning Coordinator is not responsible for implementing the ~~t~~Transmission and resource plans. However, it helps to facilitate the process whereby adequate resources and ~~t~~Transmission ~~f~~Facilities are placed into service in a timely and efficient manner through coordinated planning with the ~~Resource Planners,~~ Transmission Planners~~, and possibly others through the coordinated planning process~~.

Part 4 - Transmission Planner

The Transmission Planner develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.[2] ~~area of purview.~~

The Transmission Planning function is typically associated with the Transmission Ownership function. The Transmission Planner performs the tasks of modeling, simulating and assessing the performance of the Transmission system under a range of future scenarios on a recurring basis. As Transmission system performance deficiencies are identified through this process, the Transmission Planner studies alternative solutions for correcting the deficiencies. Through interactions with various stakeholders, the Transmission Planner ultimately arrives at a recommended Corrective Action Plan that will resolve the identified deficiencies. For solutions that involve Transmission system capacity expansion, the associated Transmission Owner(s) is responsible for implementing the solution.

Both the Transmission Planner and Planning Coordinator perform assessments to evaluate whether future Transmission system performance will meet the minimum acceptable system performance requirements. The Transmission Planner and Planning Coordinator may consider different system conditions (and BES Facilities) in performing their assessments. This flexibility allows the Transmission Planner and Planning Coordinator to study a wider range of system conditions, which leads to a more complete and comprehensive assessment of the BES. For example, a Transmission Planner may set higher System performance criteria for a particular area under assessment.

The Transmission Planner assessment includes the collection of Transmission assets over which the Transmission Planner is responsible for planning ("TP Area"). The Planning Coordinator assessment includes the collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning ("PC Area"). The PC Area is normally comprised of more than one TP. Every Facility must have one associated Transmission Planner and at least one Planning Coordinator. This means that every Facility in the TP Area should be included in the assessment conducted by the TP.

As noted above, this typically aligns with the Transmission system facilities owned by an associated Transmission Owner(s). Because of the interconnected nature of the Bulk Electric System, the Transmission Planner works with other Transmission Planners to periodically update power system models used to perform simulations. Information needed to update these models is collected from various functional entities within a particular Transmission Planner's area of purview. Power system modeling data is also "rolled up" by the Transmission Planner(s) to the Planning Coordinator to support development of Interconnection level models.[3] ~~, *i.e.*, those facilities for which the Transmission Planner develops reinforcement and corrective action plans resulting from studies and analysis of system performance and interconnection of facilities. This means that the Transmission Planner's area is not defined by the extent of the models it uses or studies that it performs since any planner can assess and perform simulations on readily available interconnection wide models. The BES facilities in its area, *i.e.*, under its purview, are generally contiguous.~~

[2] Definition of Transmission Planner (effective July 1, 2016) from the NERC Glossary of Terms. In the Glossary, Planning Coordinator and Planning Authority are defined interchangeably.

[3] In some instances, the same entity may serve as both a Transmission Planner and Planning Coordinator.

~~Traditionally transmission planning has been associated with one or more Transmission Owners, *i.e.*, reinforcement and corrective action plans must be associated with the facilities of certain Transmission Owners. In some cases where transmission ownership crosses a state line, the BES facilities on one side of a geographic boundary line may be in one Transmission Planner Area while the remaining facilities may be in another. As such, the Transmission Planner Area is not constrained to fit within one Reliability Coordinator or Transmission Operator Area. However, the Transmission Planner Area can only be smaller than or equal to the area of its related Planning Coordinator.~~

~~Develop Transmission Expansion Plans~~. The Transmission Planner evaluates the impact of ~~facilities that will be needed in response to~~ long-term ~~requests for t~~Transmission ~~s~~Service requests, and the ~~needed to~~ integration~~e~~ of new generation, ~~t~~Transmission, and end-use customers, ~~into the Bulk Electric Systems~~on the planned Transmission system performance. In evaluating requests ~~developing plans~~ for long-term ~~t~~Transmission ~~s~~Service or~~and~~ new interconnection~~s requests~~, the Transmission Planner is expected to coordinate ~~plans or engage in joint planning~~ with other Transmission Planners, as appropriate, to ensure new service/facilities do not adversely affect the reliability of neighboring ~~t~~Transmission systems.

~~Based on customer requests for transmission service, native load growth, changes in existing native load, and the planning procedures and protocols established for their Transmission Planning Areas, the Transmission Planners will develop transmission plans to accommodate long-term firm transmission service requests and native load requirements with due regard to established reliability needs. While developing these plans, the Transmission Planner may provide alternate solutions and evaluate alternatives suggested by entities requesting customer service.~~

The Transmission Planner~~s~~ provide~~s~~ its assessment results ~~transmission plans~~ to ~~its~~ the appropriate Planning Coordinator for review to ensure that the impacts on the interconnected systems are duly addressed. In reporting its ~~transmission expansion plan~~assessment results to the Planning Coordinator, the Transmission Planner is expected to assess whether its plans for new or reinforced facilities meet reliability needs or whether corrective plans are necessary. The Transmission Planners work with the Planning Coordinator to identify potential alternative solutions, including solutions proposed by stakeholders, to meet interconnected Bulk Electric System requirements.

Part 5 - Resource Planner

The Resource Planner develops a long-term (generally 1 year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Resource Planner area. Note: The term "resource" is to be understood to include supply resources and demand-side resources (such as dispatchable loads).

The boundaries for the Resource Planner area are basically defined by the location of the specific loads being considered for resource adequacy. The loads under considerations are generally contiguous and form the fundamental input for analysis of resources such as loss of load studies. The Resource Planning function may be performed by one or more Resource Planners within a Planning Coordinator area, Transmission Planner or Reliability Coordinator Area; however, the Resource Planning Function could be performed by one Resource Planner that covers one, or more than one, Planning Coordinator area, Transmission Planner Area or Reliability Coordinator Area. As such the Resource Planner area is not constrained to fit within the footprint of any other functional entity. The analysis and development of resource plans by their very nature will need to consider generation capacity and other resources outside the area defined by the specific loads as well as the transmission capability to access those resources.

In some markets, market rules may require the same organization to assume the role of both the Planning Coordinator and the Resource Planner. For example, in those markets where there are no entities responsible for or obligated to serve load, the Planning Coordinator will generally assume the Resource Planner's role. In these cases, the Planning Coordinator identifies the need for additional resources to be provided by the market and performs the Resource Planning Function.

Types of Resource Planning

Resource planning, in a generic sense, may be divided into two types:

- Planning conducted by an organization under the authority of legislation, regulation order, tariff or market rule. Such planning will typically be conducted in an open process and subject to industry, public and stakeholder review. It will have as one objective, ensuring resource adequacy.
- Planning directed to identifying and realizing commercial opportunities. Such plans will typically be commercially sensitive, may not be made public before required for the plan to be implemented, and will not be directed to ensuring resource adequacy.

The Resource Planner described in the Model is associated with the former type of planning, *i.e.*, planning having a mandate to ensure resource adequacy.

The latter type of planning, which is driven primarily by commercial opportunity, may be viewed as an activity associated with generation ownership. However, resource planning that is purely commercially-driven clearly will have an impact on resource adequacy. The Resource Planner, with its mandate for resource adequacy, must reflect to the extent possible commercially-directed planning affecting its Resource Planner area.

Part 6 - Transmission Operator

The Transmission Operator acts or authorizes action to connect to, disconnect from or reconfigure (switching operations) Facilities classified as Transmission assets, as described by the following:

a. Actions may include direct or indirect control of Transmission assets from a Control Center to conduct operations during Normal and Emergency conditions.

b. Authorizations to act may include orders directing designated field personnel with Transmission System switching responsibilities to perform switching operations on Facilities classified as Transmission assets during Normal and Emergency conditions.

The Transmission Operator ~~operates or directs the operation of transmission facilities, and~~ maintains local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility. The Transmission Operator achieves this by operating the ~~t~~Transmission system within its purview in a manner that maintains proper voltage profiles and System Operating Limits, and honors ~~t~~Transmission equipment limits established by the Transmission Owner. The Transmission Operator is under the Reliability Coordinator's direction respecting wide-area reliability considerations, that is, considerations beyond those of the system and area for which the Transmission Operator has responsibility and that include the systems and areas of neighboring Reliability Coordinators. The Transmission Operator, in coordination with the Reliability Coordinator, can take action, such as implementing voltage reductions, to help mitigate an Energy Emergency, and can take action in ~~s~~System restoration.

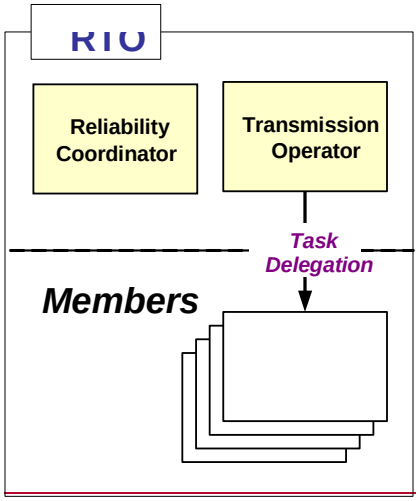
~~Note that the Model does not attempt to define what is and isn't a transmission facility, versus a generating facility. As discussed in Section II-13, this is assumed to be defined elsewhere by NERC or by governmental authorities.~~

~~**Maintenance**. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Owner then develops or arranges for the development of the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provides those schedules to the Reliability Coordinator and others as needed.~~

~~The organization serving as Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, which is ultimately responsible for maintaining its owned transmission facilities.~~

~~**Bundled with the Reliability Coordinator or Transmission Owner**. A single organization may be the functional entity for multiple Functions. In such a case, the functional entities are said to be "rolled up" or "bundled" into a single organization. An organization may be a Transmission Operator without being a Reliability Coordinator or Transmission Owner. However, in many cases the Transmission Operator is bundled with one of these functional entities.~~

~~**Bundled with Reliability Coordinator**. For example, consider an RTO with several members. The RTO registers with NERC as a Reliability Coordinator and Transmission Operator and is NERC-certified for both. The RTO then delegates/assigns some of the Transmission Operator Tasks to its members.~~



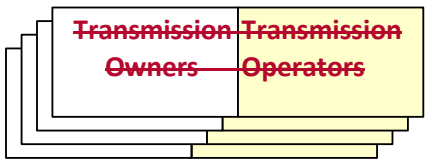
~~***Figure 1 – Transmission Operator bundled with Reliability Coordinator***~~

~~**Bundled with the Transmission Owner**. In other situations, the RTO registers with NERC as the Reliability Coordinator, and its members register as Transmission Owners and Transmission Operators, as shown in Figure 2. In this case, the Model views the RTO as responsible for complying with Reliability Standards associated with the Reliability Coordinator and would be NERC-certified as such. The RTO members would be responsible for complying with all Reliability Standards associated with the Transmission Operator, and would be NERC certified as such.~~

~~**RTO**~~

~~**Reliability Coordinator**~~

~~***Members***~~



~~***Figure 2 – Transmission Operator bundled with Transmission Owner***~~

Part 7 - Interchange Coordinator

The e-tagging process exists for scheduling Transmission usage by entities who have contracted for Transmission access. NAESB maintains the e-tagging specification. The Interchange Coordinator is equivalent to the tag authority described in the specification. (NAESB states this service has been assigned to the Sink Balancing Authority. The functional model envisions that the Sink Balancing Authority may serve as its own Interchange Coordinator or have this service provided by a separate organization.)

The "authority service"[4] is the focal point for all interactions with an e-Tag and maintains the single authoritative "copy of record" for each e-Tag received. Every Sink Balancing Authority is responsible for registering the URL of an "authority service." The authority service forwards all valid received RFI to each entity identified in the transaction as having "approval" or "viewing" rights over that RFI, and collects approvals/denials issued by these approval services. Based on time and the message(s) received from the approval services, the authority service arbitrates and sends the final disposition of the request to each entity in the distribution list. The authority service also provides the capability for both the agent (requestors of service) and approval services to interrogate the current approval state of any transaction RFI on demand.

~~The Interchange Coordinator collects approvals or denials for Arranged Interchange from Balancing Authorities and Transmission Service Providers and verifies the validity of the source and sink. The NERC Tag Authority provides this service that had been assigned to the Sink Balancing Authority.~~

~~The Interchange Coordinator provides the Balancing Authority with the individual bilateral Arranged Interchange. The Balancing Authority must track the individual Interchange Schedules in case one or more of them are curtailed by the Reliability Coordinator or by the Balancing Authority in those cases where a generator or load is interrupted. The Balancing Authority then creates a "net" interchange total for use in its energy management system as well as a "net" interchange for each neighboring Balancing Authority. The net Interchange Schedule for each neighboring Balancing Authority is used by the Receiving Balancing Authority for checkout with the neighboring Balancing Authorities.~~

~~All bilateral Interchange Transactions *that cross a Balancing Authority Area boundary* are coordinated through the Interchange Coordinator.~~

~~While the approval/denial process may utilize tools (such as computer software and communication protocols), the Model envisages that the Interchange function will be assigned to an actual organization. A Balancing Authority may serve as its own Interchange Coordinator or have this service provided by a separate organization.~~

~~**Assessing ramping capability and connectivity**. The Balancing Authority approves/denies the capability to ramp the Arranged Interchange in or out and notifies the Interchange Coordinator. The connectivity of adjacent Balancing Authorities is also verified by the Balancing Authorities before responding to the~~

[4] Definitions from NAESB:
e-Tag Agent Service: Software component used to generate and submit new e-Tags, corrections, and profile changes to an e-Tag Authority Service and to receive state information for these requests.
e-Tag Authority Service: Software component that receives e-Tag Agent Service and e-Tag Approval Service requests and responses and forwards to the appropriate approval service. Also maintains master copy of e-Tag (all associated requests), the composite state of the e-Tag, etc. and responds to queries regarding the e-Tags in its possession.
e-Tag Approval Service: Software component used to indicate individual approval entity responses when requested by the e-Tag Authority Service, as well as submit profile changes.

~~Interchange Coordinator.~~

~~**Ensuring balanced, valid Interchange Transactions**. The Interchange Coordinator also ensures that the resulting Confirmed Interchange Transactions is balanced and valid prior to physical delivery. This means:~~

- ~~The source MW must be equal to the sink MW (plus losses if they are "self-provided"), and~~
- ~~All reliability entities involved in the Arranged Interchange are currently in the NERC registry.~~

~~Only when it receives approvals from the Transmission Service Providers and Balancing Authorities, does the Interchange Coordinator direct the Balancing Authorities to implement the Transaction. If any of these entities TSPs or BAs does not approve the Arranged Transaction, then the Interchange Coordinator does not authorize the Transaction to become Confirmed Interchange.~~

~~**Curtailments**. The Interchange Coordinator coordinates curtailments of Confirmed Interchange ordered by the Reliability Coordinator by notifying the Balancing Authorities, Transmission Service Providers, and Purchasing-Selling Entities. The Interchange Coordinators also communicates and coordinates the resulting modified Arranged Interchange that result from the curtailments.~~

Part 8 - Transmission Service Provider

The Transmission Service Provider authorizes the use of the transmission system under its authority. In ~~most~~ some cases, the organization serving as Transmission Service Provider is also the market operator.

Role in approving Interchange. The Transmission Service Provider approves Arranged Interchange by comparing the ~~t~~Transmission ~~s~~Service previously arranged by the ~~t~~Transmission ~~c~~Customer (Purchasing-Selling Entity, Generator Owner, Load-Serving Entity) with the ~~t~~Transmission information supplied by the Interchange Coordinator. The Transmission Service Provider also ensures that there is a contiguous ~~t~~Transmission path and that adjacent Transmission Service Providers~~SPs~~ are on the ~~s~~Scheduling ~~p~~Path. The Transmission Service Provider then provides its approval or denial to the Interchange Coordinator.

Providing Transmission and Ancillary Service. As its name implies, the Transmission Service Provider provides transmission service and Ancillary Service to transmission customers, such as Generator Owners, Load-Serving Entities, and Purchasing-Selling Entities. The Transmission Service Provider determines Available Transfer Capability based on the established Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits (by various entities including the Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator), and coordinates ATC with other Transmission Service Providers. The Transmission Service Provider manages the requests for transmission service according to the Transmission Owner's tariff, and within the operating reliability limits determined by the Reliability Coordinator. The Transmission Service Provider ensures necessary Ancillary Services are provided to the Transmission Operator and Balancing Authority. The Transmission Service Provider does not itself have a role in maintaining system reliability in ~~r~~Real time — that is done by the Reliability Coordinator and Transmission Operator and Balancing Authority.

The Transmission Service Provider arranges for transmission loss compensation and Ancillary Service requirements with the Balancing Authority.

Part 9 - Transmission Owner

The Transmission Owner owns its transmission facilities and provides for the maintenance of those facilities. It also specifies equipment operating limits, and supplies this information to the Transmission Operator, Reliability Coordinator, and Transmission Planner and Planning Coordinator.

In many cases, the Transmission Owner has contracts or interconnection agreements with generators or other transmission customers that would detail the terms of the interconnection between the owner and customer.

~~**Relationship with the Transmission Operator**. The organization serving as Transmission Owner may operate its transmission facilities or arrange for another organization (which may or may not be a Transmission Owner) to operate and/or maintain its transmission facilities.~~

Maintenance. The Transmission Owner provides the overall maintenance plans and requirements for its equipment, specifying, for example, maintenance periods for its transformers, breakers, and the like. The Transmission Owner then develops or arranges for the development of the detailed maintenance schedules (dates and times) based on the Transmission Owner's maintenance plans and requirements, and provides those schedules to the Reliability Coordinator and others as needed.

The organization serving as Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, which is ultimately responsible for maintaining its owned transmission facilities.

~~See "Transmission Operator," Section "Bundling with the Reliability Coordinator or Transmission Owner"~~

Part 10 - Distribution Provider

The Distribution Provider provides the physical connection between the end-use customers, distribution-connected energy resources, and the BES~~electric system~~, including customers served at ~~t~~Transmission level voltages. The Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. One Distribution Provider may be directly connected to another Distribution Provider, such connections must be reported to the Balancing Authority even though ~~and~~ not directly connected to the BES~~ulk Electric System~~.

The Distribution Provider maintains "local" safety and reliability and is responsible for the distribution facilities to serve end-use customers and distribution-connected energy resources. The Distribution Provider provides the switches and re-closers necessary for emergency action and information necessary for the Transmission Operator and Transmission Planner. The Distribution Provider may need to demonstrate manual ~~l~~Load-shedding capability to the Balancing Authority and Transmission Operator. Design and maintain protective relaying systems, under-frequency load-shedding systems, under-voltage Load-shedding systems, and Remedial Action Schemes that interface with the Transmission system.

~~The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well.~~ Unlike the Load-Serving Entity, the Distribution Provider has the facilities or assets ("wires") and does not take title to any energy. However, while these functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these functions together.

~~Part 11 – Generator Operator~~

~~The Generator Owner may operate its generating facilities or designate a separate organization to perform the Generator Operation Function.~~

~~The Generator Operator operates, or directs the operation of generation facilities. The Generator Operator supports the needs of the Bulk Electric System up to the limits of the generating facilities in its purview. Ultimately the Generator Operator's role is to meet generation schedules, manage fuel supplies, and provide frequency support and reactive resources without jeopardizing equipment.~~

~~**Relationship with the Generator Owner.** The organization that serves as Generator Operator may also be the owner of the generation facilities it operates, or it may be a separate organization designated by the Generator Owner to operate the facilities. The Generator Operator receives maintenance and performance verification schedules from the Generator Owner, and develops operating and unit commitment plans based on these schedules~~

~~**Relationship with the Transmission Operator.** The Generator Operator provides reliability related services through arrangements or by direction from the Transmission Operator for support of the Bulk Electric System. The Generator Operator provides maintenance schedules, generator status, and AVR status to the Transmission Operator. The Generator Operator receives notification of transmission system problems affecting its generator from the Transmission Operator or Reliability Coordinator.~~

~~**Relationship with the Balancing Authority.** The Generator Operator provides unit commitment schedules, generator status, and operating and availability status of generating units to the Balancing Authority.~~

Relationship with the Reliability Coordinator. The Generator Operator provides annual maintenance plans, and operational data to the Reliability Coordinator. The Generator Operator takes actions based on directives from the Reliability Coordinator for the needs of the Bulk Electric System.

Relationship with Purchasing Selling Entity. The Generator Operator receives notice of Arranged Interchange approved by the Purchasing Selling Entity.

Part 12 – Generator Owner

The Generator Owner owns its generation facilities and provides for the maintenance of those facilities.It also provides verified equipment operating limits and supplies this information to the Generator Operator, Reliability Coordinator, Transmission Planner and Planning Coordinator.

In many cases, the Generator Owner has contracts or interconnection agreements with Transmission Owners or Distribution Providers that detail the terms of the interconnection between these parties.

Relationship with the Generator Operator. The organization serving as Generator Owner may operate generation facilities, or arrange for another organization to do so. In addition, the organization serving as Generator Owner may perform maintenance and facility verification, or may arrange with another organization to do so.

Part 13 – Purchase-Selling Entity

The Purchasing Selling Entity (PSE) arranges for and takes title to energy products (capacity, energy and reliability-related services) that it secures from a resource for delivery to a Load- Serving Entity (LSE). The PSE also arranges for transmission service with the Transmission Service Provider that provides transmission service to the LSE under a tariff or market rule.

The Purchasing-Selling Entity initiates a bilateral Interchange between Balancing Authority Areas by submitting a Request for Interchange (RFI) to the Interchange Coordinator.

Part 14 - Load-Serving Entity

The Load-Serving Entity (LSE) arranges for the provision of energy Resources and Ancillary Services to its Balancing Authority and Resource Planner in order to supply its end-use customers, but does not provide distribution services ("wires"). ~~The LSE defined in the Model is not to be confused with or equated to the LSE as defined in any tariff or market rule.~~

~~Today, o~~Organizations serving as Load-Serving Entities may also be Generation Owners and can self-provide, or have contracts with other Generator Owners for capacity, ~~and~~ energy and Ancillary Services to serve the Load-Serving Entity~~'s~~ customers, or purchase capacity, ~~and~~ energy, and Ancillary Services from non-affiliated Generator Owners through a Purchasing-Selling Entity (or Market Operator), or employ a combination of these three options.

The Load-Serving Entity reports its ~~generation~~ resource (affiliated and non-affiliated) arrangements to serve load to the Balancing Authority, which forwards this information to the Reliability Coordinator, for day-ahead analysis.

The LSE may contract for ~~reliability-related services~~ Ancillary Services through the Transmission Service Provider or the ~~M~~market ~~O~~operator (if the Load-Serving Entity is part of a market or pool) or directly from Generator Owners or loads.

~~The same organization may serve as the Distribution Provider and Load-Serving Entity, but they may be separate organizations as well.~~ Unlike the Distribution Provider, the Load-Serving Entity, does not have Bulk Electric System assets ("wires") but does take title to energy. However, while these functions are distinct, in many cases an organization, such as a vertically integrated utility, bundles these functions together.

~~The Functional Model assigns to t~~The Load-Serving Entity is responsible for the identification of loads for ~~c~~Curtailment and those critical customer loads that are to be excluded from the load-shedding systems, and the development of load profiles and load forecasts. ~~Please see Section II, 114: Roles in Load Curtailment for more detailed information.~~

The Load-Serving Entity communicates requests for ~~voluntary c~~Curtailment to the appropriate end-use customer loads~~, thereby ensuring that these loads will in fact be curtailed~~.

~~Part 15 – Compliance Enforcement Authority~~

~~NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC.~~

~~Part 16 – Standards Developer~~

~~The Standards Developer is written to be NERC. The Reliability Standards referenced in the Model consist of standards developed by either NERC or a Regional Entity and that are approved by NERC and subsequently by governmental authorities. This would therefore not include regional reliability criteria that are not submitted to NERC for approval. This is discussed further in Section II.~~

~~Part 17 - Market Operator (Resource Integrator)~~

~~Market Operations is not a reliability Function. It is included in the Model to provide a linkage between reliability Functions and commercial functions. The associated functional entity is the Market Operator (Resource Integrator). The term Resource Integrator replaces Resource Dispatcher used in Version 3 of the Model. This recognizes that integration of resources is the essential feature, not resource dispatch, which is the responsibility of the Balancing Authority.~~

~~The Market Operator is described further in Section II, Technical Discussions.~~

Part 18 - Reliability Assurer

The Reliability Assurer is subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. The Reliability Assurer assures the reliability of the Bulk Power System in North America by developing and enforcing Reliability Standards; annually assessing seasonal and long-term reliability; monitoring the Bulk Power System through system awareness; and, educating, training, and certifying industry personnel.

~~In Version 4 of the Model, the Reliability Assurer entity and the Reliability Assurance Function replaced Version 3's Regional Reliability Organization entity and the Regional Reliability Assurance Function.~~

~~The change to Reliability Assurer reflected the fact that a name specific to the Model is preferable to a name already in use in another context. Moreover, since this Function can be performed on other than a regional basis, the Functional Model allows for the assignment to be made to an organization other than a Regional Entity.~~

~~The changes therefore provide NERC with flexibility in assigning the functional entity for Reliability Assurance.~~

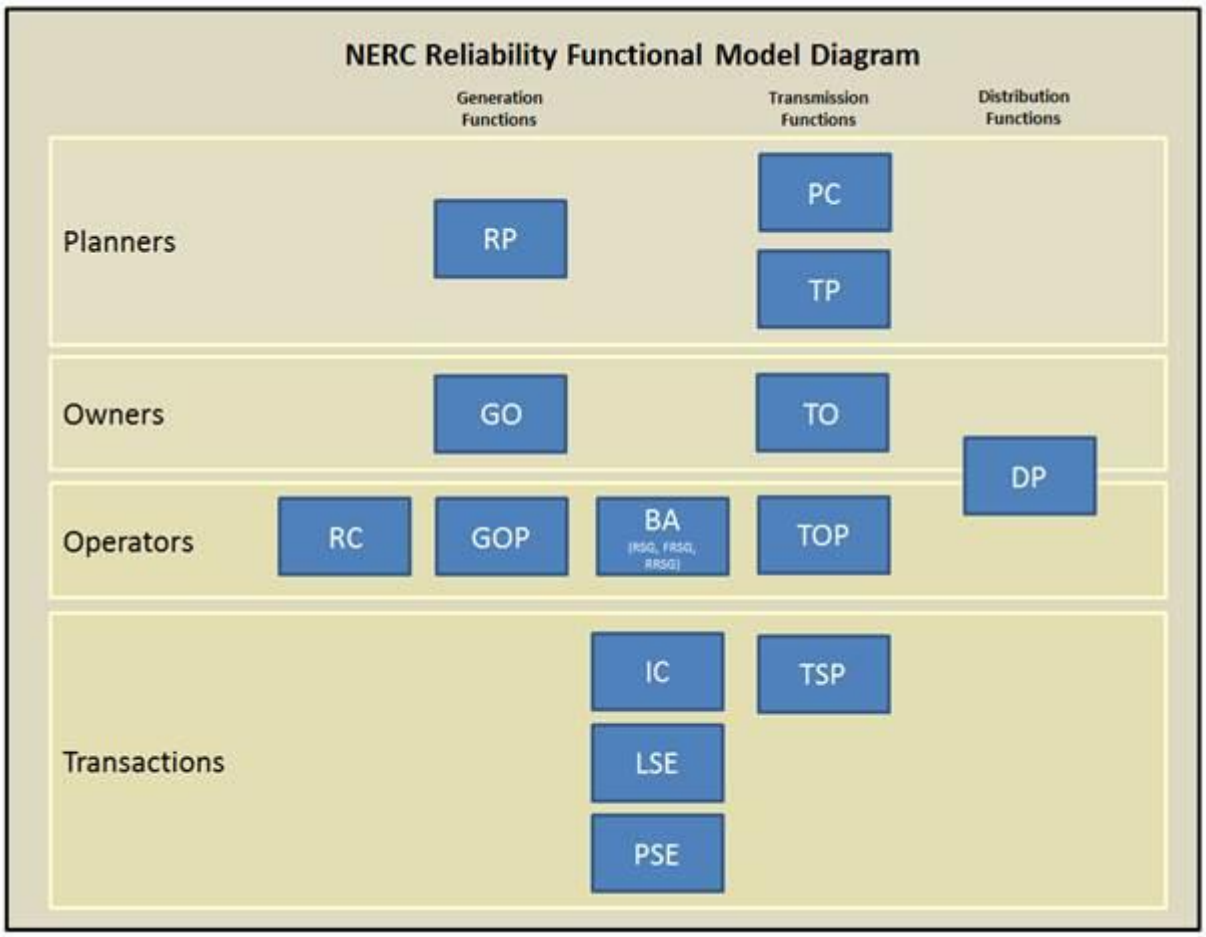
~~The role of the Reliability Assurer may be considered to provide "defense-in-depth." That is, the Reliability Assurer provides an independent assessment of Tasks performed by other functional entities, or facilitates or coordinates such Tasks. While the specific role of the Reliability Assurer is not fully developed at the present time, the following are representative of the Tasks that might be performed:~~

- ~~Perform high level evaluations, such as at a regional or Interconnection level, of transmission and resource adequacy. These evaluations may be based on a review of the plans of Transmission Planners.~~
- ~~Develop regional reliability plans, to ensure there are no reliability gaps, or no missing or ambiguous responsibilities or relationships.~~
- ~~Perform high-level evaluations, such as at a regional or Interconnection level, of protection systems as they relate to the reliability of the Bulk Electric System.~~
- ~~Perform disturbance analysis evaluations.~~

~~The selection of particular Tasks for the Reliability Assurer will reflect NERC's judgment on which Tasks merit such a "defense-in-depth" approach.~~

SECTION 2 – TECHNICAL DISCUSSION

The below diagram provides an illustration of how the various functional entities can be categorized.



~~Part 1 – General Clarifications of the Functional Model~~

~~The general features of the Functional Model are described in the Introduction, Purpose and Guiding Principles sections of the Model. In brief:~~

~~The NERC Reliability Functional Model ("the Model") provides the framework for the development and application of NERC's Reliability Standards, as follows:~~

- ~~The Model describes a set of Functions that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to a functional entity, that is, the entity that performs the Function's Tasks. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions).~~

- NERC's Standard Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a functional entity, as defined in the Model.
- This is possible because a given standard requirement will be logically related to a Task within a Function. A standards requirement will be very specific whereas a Task will be more general in nature.
- NERC's compliance processes require specific organizations to register as functional entities and comply with standards requirements assigned to the functional entities.
- The Model's Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.

The NERC Reliability Functional Model ("the Model") does NOT address:

- Entity Certification
- Registration
- Compliance
- Sanctions

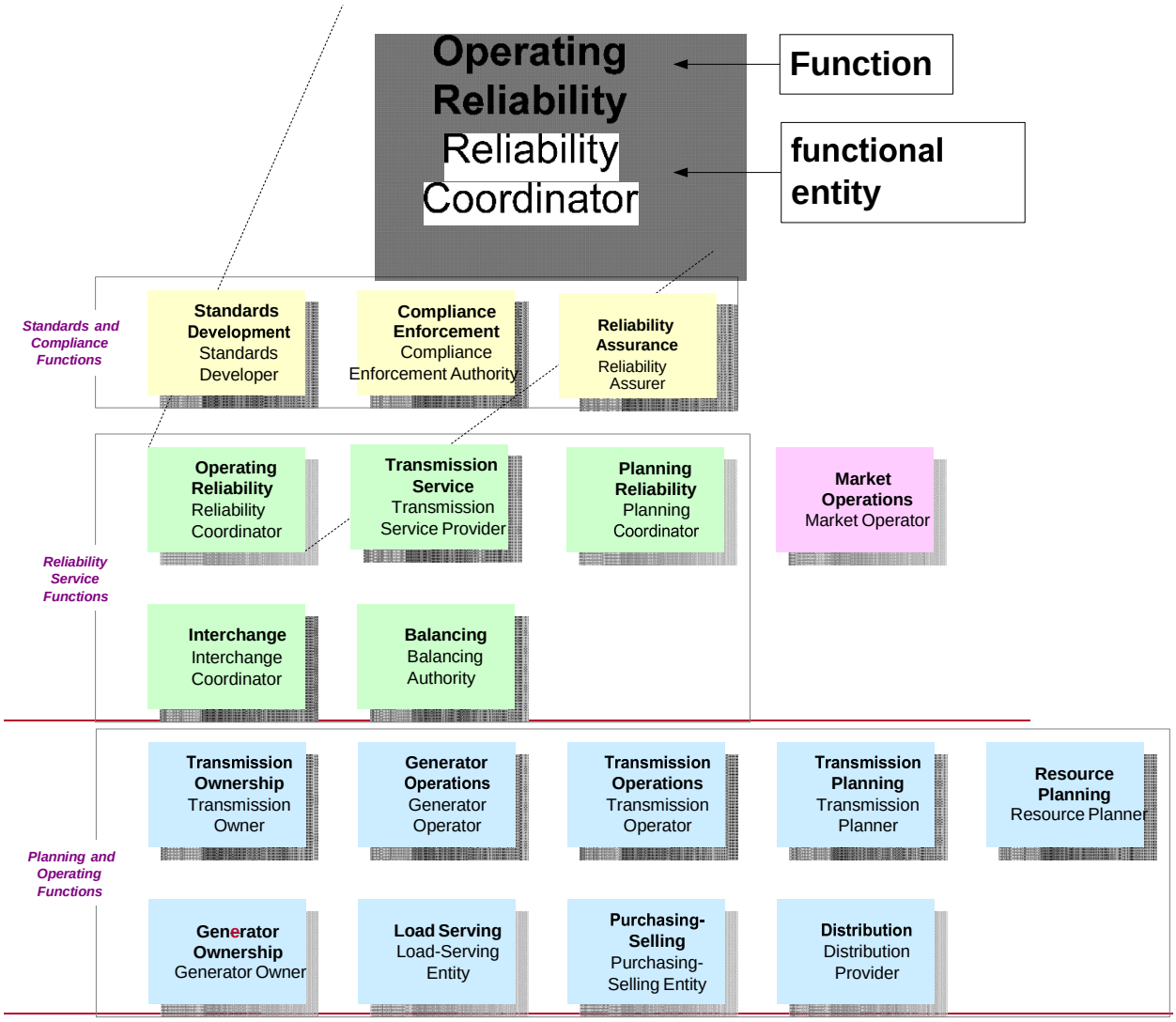
There are a number of clarifications that are important for those involved in developing standards and monitoring compliance with them. These clarifications are generally made in the Model itself, but because of their importance and potential for misinterpretation, they warrant being repeated.

The Model is a guideline, it is not prescriptive. The Model is not a standard, and does not have compliance requirements. The Model is a guideline for the development of standards and their applicability; it is not a NERC requirement. Standards developers are not required to include tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that conflict with the Model. The Reliability Standards requirements take precedence over the Model.

A Functional Entity is not an actual organization. The Model describes Tasks performed by functional entities, which are in effect generic *classes or categories* of organizations. The Model itself does not address *specific* organizations. The Model, for example, describes the Reliability Coordinator, a functional entity; the Model does not reference PJM and MISO, which are specific organizations. It is through the NERC registration process that the PJM and MISO organizations become a member of the category of organization called Reliability Coordinator, and thereby responsible for meeting standards requirements specified for the Reliability Coordinator.

Reliability is best served if there is consistency of definitions within all NERC documents. These documents include, but are not limited to, the Functional Model, the NERC Rules of Procedure and Glossary of Terms.

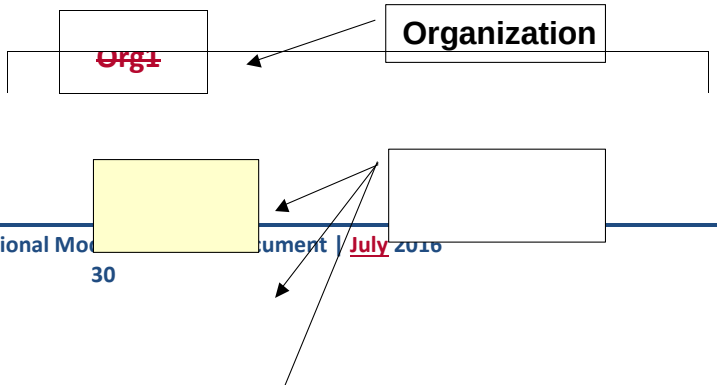
Every Function has an associated functional entity. A Function is a set of related reliability Tasks; whereas the functional entity is the name given to the category of organization that performs these Tasks. The diagram (Figure 3) of the Model includes two names within each Function box. The Function is shown in a larger typeface with the associated functional entity underneath.

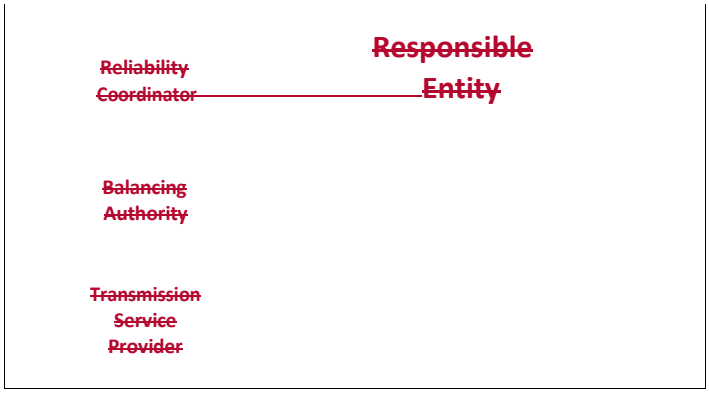


~~Figure 3 – Function and Functional Entity~~

~~Organizations, such as Regional Transmission Organizations or integrated utilities, may register with NERC as Responsible Entities by identifying which Functions they perform.~~

~~For example, as shown in Figure 4 an RTO (organization) may register with NERC to be a Reliability Coordinator, Balancing Authority, and a Transmission Service Provider. In this case we say that the RTO is the **Responsible Entity** for the Operating Reliability, Balancing, and Transmission Service Functions. We also use the expression that the RTO has "rolled up" these three Functions and is responsible for ensuring that the Tasks within each of those Functions are performed and all applicable standards requirements met.~~




~~Reliability Coordinator~~
~~Responsible Entity~~
~~Balancing Authority~~
~~Transmission Service Provider~~

~~**Figure 4 — Organizations may "roll up" more than one functional entity.**~~

Part 2 - Reliability Standards

The Functional Model describes the Standard Development Function and the Standards Developer functional entity and how these are related to Reliability Standards.

Reliability Standards can be developed at the North American level as well as at the regional level and can therefore be placed in two categories:

Reliability Standards Developed at the North American Level Within NERC

NERC, under regulatory authority, develops and maintains Reliability Standards using the NERC Reliability Standards Development Procedures. The standards are applicable across North America upon approval by governmental authorities, unless specifically stated otherwise within the standard, and enable NERC and Regional Entities to monitor and enforce compliance with the standards requirements.

NERC can use the Reliability Standards Development Procedures to approve a variance from a NERC Reliability Standard; the variance then becomes part of the standard. The three categories of variance are:

- Entity Variance that applies to an area less than a NERC Region
- Regional Variance that applies to a NERC Region but less than an Interconnection
- Regional Variance that applies to a NERC Region on an Interconnection-wide basis.

1. Reliability Standards Developed Within a Regional Entity

Regional Entities may develop and propose to NERC regional reliability standards that:

- Set more stringent reliability requirements than the NERC Reliability Standard
- Cover matters not covered by an existing NERC Reliability Standard.

Alternatively, NERC may direct Regional Entities to develop a regional reliability standard in order to implement a NERC Reliability Standard. Such a regional reliability standard, upon approval by NERC, becomes part of the NERC Reliability Standard.

Regional Entities must use a NERC-approved development process to develop these regional reliability standards. Such regional reliability standards, upon approval by NERC, become NERC Reliability Standards. As appropriate, NERC will approve the regional reliability standard as an:

- Interconnection-wide regional standard, or
- Non-Interconnection-wide regional standard.

Regional Criteria. Regional Entities may develop regional reliability criteria that are necessary to implement, to augment or to comply with Reliability Standards, or to address issues not within the scope of Reliability Standards. Such criteria are not approved by NERC and are not (NERC) Reliability Standards. As such, regional criteria, while clearly serving a reliability purpose, are best considered to be outside of the (NERC) Functional Model.

Part 13 - Market Operations (Resource Integration)

Market OpOperations is not a reliability Ffunction. NERC does not assign standards requirements to the Market Operator. Nevertheless, Mmarket Ooperations, a commercial or market function, is included in the Functional Model, in order to provide an interface point between reliability and commercial functions.

The role of the Mmarket Ooperator[5] also varies in design and responsibilities depending on whether resources are dispatched within a full-service market or where there is not a full-service market. However, , but all Mmarket Ooperators perform a resource integration task of one form or another under a resource integration protocol set of market rules that is are recognized by a state, federal, or provincial regulator. A resource integration protocol is the method used to determine the merit order of the generation to be dispatched. Generally, resource integration protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority. The basis and results for the resource integration algorithms are generally the same for cost-based and bid-based dispatch, which is why the Functional Model accommodates either type of protocol. Resource integration is discussed further in the following section II-4, Functional Model and Market Structures.

Multiple Balancing Authorities Within a Market Area. If the market area includes more than one Balancing Authority Area, then the market operator will also provide each Balancing Authority with the Net Interchange Schedule that results from the resource plan ("Resource Dispatch Interchange Schedule", or RDIS). Each Balancing Authority's RDIS will be an import or export to the Balancing Authority Area, and the sum of all RDISs within the market area must add to zero at each dispatch cycle.

Resource integration is discussed below for the cases of a full-service market and where there is no full-service market. Versions 4 and 5 of the Model refer to the entity as "Market Operator (Resource Integrator)", where Resource Integrator is seen as a better term than Market Operator in areas not having a full-service market. For simplicity, the discussion below uses only the term Market Operator, to apply even where there is not a full-service market.

1. The Market Operator in a Full-Service Market.

A full-service market is one which offers both the commercial services such as integrating resources ahead of Real-time and settlement after the completion of Implemented Interchange and dispatch cycles, and implement the resource plan in Real-time, making adjustment as necessary to meet other reliability requirements not envisaged during the resource integration process (for example, reliability constraints). In a full-service market, the Market Operator tasks involve integrating resources in accordance with established market rules. Following its market rules and using available market mechanisms, the Market Operator integrates market resources by establishing a generation dispatch plan to meet the load forecast for the upcoming dispatch cycle (typically five minutes or longer).

This generation dispatch plan is usually a function of the generators' incremental bids ("merit order"). The established generation dispatch plan is submitted to the Balancing Authority for implementation. When the plan is tested for implementation, and limitations caused by transmission congestion are identified, the Balancing Authority will adjust the dispatch schedules accordingly. This constitutes a "security-constrained" dispatch.

[5] For simplicity, only the term "market operator" is used; this is intended to apply even where there is not a full-service market.

Bid-Based Resource Integration. In those areas of North America having a full-service market, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will direct the submission of bids via the Generator Operators to the Market Operator. The Market Operator, in turn, provides the Balancing Authority with the generator dispatch plan, so that the generators within the market footprint would be instructed to operate at the same incremental bid. Transmission constraints may cause the actual dispatch to deviate from the dispatch plan. Re-dispatch methods used to relieve the congestion may use: direct resource assignments, area / zonal dispatch signals, or bus-signals. The zonal and bus methodologies are often referred to as "Locational Marginal Pricing," or LMP.

Relationship between the Market Operator and Balancing Authority. In a full-service market, there is a close relationship between the ~~M~~market ~~O~~operator and the Balancing Authority. A full-service ~~M~~market ~~O~~operator performs resource integration tasks and is assigned the tasks of:

- Determining the generation dispatch plan (unit commitment) ahead of time
- Integrating scheduled interchange into that generation plan
- Designating which generators are available for regulation service
- Providing the generation dispatch plan to the Balancing Authority ahead of ~~r~~Real-~~-~~time.

The Balancing Authority receives the plan, and implements it in real time.

2. The Market Operator Where There is not a Full-Service Market~~.~~

Cost-based Resource Integration. Where there is not a full-service market, the Market Operator will often be a traditional, vertically-integrated utility that acts also as Balancing Authority. The utility will dispatch its resources based on its incremental costs (fuel and operations and maintenance) and losses. The regulatory authority might specify the accounting rules for calculating these costs.
~~In jurisdictions not having a full-service market there will often be a traditional, vertically-integrated utility that may be both the Market Operator and the Balancing Authority, and most or all of the associated tasks will be performed internal to the utility. The generation dispatch plan will typically be cost-based, in contrast to bid-based dispatch in a full-service market.~~

In addition, there are jurisdictions that use a model other than full-service market and vertically-integrated utility, in particular bilateral Interchange Transactions. In this case, the organization serving as Balancing Authority will also be the ~~M~~market ~~O~~operator, operating on the basis of ~~n~~Net ~~i~~Interchange.

3. Summary: The Market Operator Using Different Structures

The table below describes how the current operating tasks may be performed by both the vertically-integrated utility and the unbundled, full-service market operator.

~~Part 4 - The Functional Model and Market Structures~~

~~This section explains how the Functional Model can accommodate different market structures by examining these structures from the perspective of resource integration protocol.~~

~~**Resource Integration Protocol**. A resource integration protocol is the method used to determine the merit order of the generation to be dispatched. Generally, resource integration protocols are either cost-based or bid-based, depending on the market rules established by the regulatory authority, as described in section II-3, Market Operations (Resource Integration). The basis and the results for the resource integration algorithms are generally the same for cost-based and bid-based dispatch, which is why the Functional Model can accommodate either type of protocol.~~

~~**Bid-Based Resource Integration**. In those areas of the U.S. and Canada having a full-service market, market protocols provide Generator Owners the ability to bid into the market. In those cases, Generator Owners will direct the submission of bids via the Generator Operators to the Market Operator. The market protocols are established by the governmental authority, such as the Federal Energy Regulatory Commission in the U.S. and provincial regulators in Canada. The Market Operator, in turn, provides the Balancing Authority with the generator dispatch plan, so that the generators within the market footprint would be instructed to operate at the same incremental bid. Transmission constraints may cause the actual dispatch to deviate from the dispatch plan. Re-dispatch methods used to relieve the congestion may use: direct resource assignments, area / zonal dispatch signals, or bus signals. The zonal and bus methodologies are often referred to as "Locational Marginal Pricing," or LMP.~~

~~**Cost-based Resource Integration**. Where there is not a full-service market, the Market Operator may be a traditional, vertically-integrated utility that acts also as Balancing Authority. The utility will dispatch its resources based on its incremental costs (fuel and operations and maintenance) and losses. The regulatory authority, such as the state public utility commission, might specify the accounting rules for calculating these costs.~~

~~**Multiple Balancing Authorities Within a Market Area.** If the Market Area includes more than one Balancing Authority Area, then the Market Operator will also provide each Balancing Authority with the net "interchange" schedule that results from the resource plan ("Resource Dispatch Interchange Schedule", or RDIS). Each Balancing Authority's RDIS will be an import or export to the Balancing Area, and the sum of all RDISs within the Market Area must add to zero at each dispatch cycle.~~

~~The table below describes how the current operating tasks may be performed by both the vertically-integrated utility and the unbundled, full-service market operator.~~

Task	No Full-Service Market: Vertically Integrated Structure	Full-Service Market: Unbundled Structure
Unit Commitment	Utility (performing as the Generator Owner) decides which units to run.	Generator Owners decides which units to make available.

Economic Dispatch	Utility (as Market Operator or Resource Integrator) performs economic dispatch calculation based on incremental costs or other requirements. Utility must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.	Market Operator collects bids from Generator Owners and develops integrated resource plans based on market rules (*e.g.*, bids). Market Operator must consider generator operating limits, which units are providing regulation service, and any commitments for bilateral arrangements.
Congestion Management	Results in different incremental costs ("lambdas").	Depending on the market structure, results in Different locational marginal prices (LMP), or Different marginal costs
Regulation Service	Utility (serving as the Balancing Authority, Load-Serving Entity, and Generator Owner) in concert with the Reliability Coordinator, determines the amount of regulation service required, and designates those units that provide the regulation service. Utility (as Balancing Authority) uses this information in its economic dispatch.	Balancing Authority, along with Reliability Coordinator, determines the amount of regulation service required. Generator Owners decide which units to bid in for regulation service. Market Operator runs bid pool for regulation service. Load-Serving Entity arranges for regulation services.
Generator Control	Utility (as Balancing Authority) pulses units that are designated by the Market Operator for regulation service. As regulating ability declines, the part of the utility that acts as Balancing Authority directs the part of the utility that acts as Market Operator to develop a new dispatch plan.	Balancing Authority pulses units that are designated by the Market Operator for meeting energy and regulation service requirements. As regulating ability declines, the Balancing Authority asks the Market Operator for a new dispatch plan.

Part 25 - Providing and Deploying Ancillary and Interconnected Operations Services~~Reliability-Related Services~~

The North American electric power system is transforming to a resource mix that relies less on coal and nuclear while integrating more natural gas, wind, solar, distributed generation, and demand response resources. Additionally, the power system will change further as micro-grids, smart networks, and other advancing technologies continue to be deployed. Recognizing that these changes represent a fundamental shift in the operational characteristics of the power system with potential reliability implications, the policies that govern Ancillary Services and the characteristics of Interconnected Operations Services may evolve to address these newer resources. Proper planning and providing system operators with the ability to manage resources in real time will be required to ensure that the appropriate levels of Interconnected Operations Services are available so that reliability is maintained as the resource mix evolves.

The Building Blocks of Reliability[6]

Based on the analysis of geographic areas that are experiencing the greatest level of change in their types of resources, a number of measures and industry practices are recommended to identify trends and prepare for the transition in resource mix. These recommendations consider both real-time operations and future planning to support frequency, ramping and voltage of the system.

Frequency – The electric grid is designed to operate at a frequency of 60 hertz (Hz). Deviations from 60 Hz can have destructive effects on generators, motors, and equipment of all sizes and types. It is critical to maintain and restore frequency after a disturbance such as the loss of generation. Frequency will immediately fall given such an event. This requires an instantaneous (inertial) response from some resources and a fast response from other resources to slow the rate of fall during the arresting period, a fast increase in power output during the rebound period to stabilize the frequency, and a more prolonged contribution of additional power to compensate for lost resources and bring system frequency back to the normal level.

Ramping – Adequate ramping capability (the ability to match load and generation at all times) is necessary to maintain system frequency. Changes to the generation mix or the system operator's ability to adjust resource output can impact the ability of the operator to keep the system in balance.

Voltage – Voltage must be controlled to protect system reliability and move power where it is needed in both normal operations and following a disturbance. Voltage issues tend to be local in nature, such as in sub-areas of the Transmission and distribution systems. Reactive power is needed to keep electricity flowing and maintain necessary voltage levels.

[6] Excerpt from North American Electric Reliability Corporation (NERC) ERS Framework Report, December 2015

Tariff Domain — Requirement for Ancillary Services. ~~The FERC open access (pro forma) tariff requires the (U.S.) Transmission Provider to provide the following Ancillary Services to all customers taking basic transmission service (Figure 5):~~

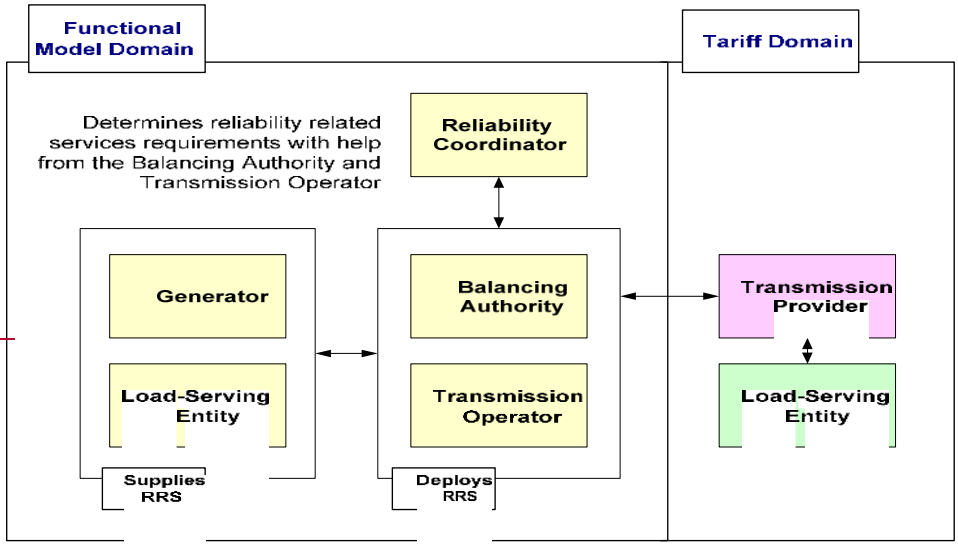


Figure 5 - Supply and Deployment of Ancillary Services and Reliability-Related Services.

The FERC pro-forma tariff requires that the Transmission Provider offer to provide Ancillary Services, as a provider of last resort, ~~the following services~~ to customers serving loads within the Transmission Provider's own area which do not purchase or self-provide:

1. Scheduling, system control, and dispatch
2. Reactive supply and voltage control from generation.
3. Energy imbalance
4. Regulation and frequency response
5. Operating reserve — spinning
6. Operating reserve — supplemental.
7. Generator Imbalance

Functional Model Domain — Interconnected Operations ~~Reliability-related~~ Services. A service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.[7] ~~The term "reliability-related services" means those services other than the supply of energy for load that are~~ These Interconnected Operations Services are physically provided by generators, transmitters and loads in order to maintain reliability.

~~Reliability-related services include voltage control and reactive power resources from generators, transmitters and loads.~~ Certain ~~t~~Transmission facilities can provide reactive support, but are not considered an Ancillary Service in the open access tariff, rather, they are considered part of basic ~~t~~Transmission service. In addition, loads may provide reserves through load-shedding or ~~d~~Demand-~~s~~Side ~~m~~Management, and may also provide frequency response.

Ancillary Services in the “tariff domain” could be served by Interconnected Operations Services ~~reliability-related services~~ in the "reliability domain.” The Functional Model explains that the Balancing Authority, alone or

[7] Definition of Interconnected Operations Services from the NERC Glossary of Terms (as of May 15, 2016).

in coordination with the Reliability Coordinator, determines the amount required and arranges for Interconnected Operations Services ~~reliability-related services~~ to ensure balance:

- The Balancing Authority determines regulation, load following, frequency response, ramping capability and contingency reserves, ~~etc.,~~ and deploys these as Interconnected Operations Services~~reliability-related services~~.
- The Transmission Operator determines the reactive resources ~~reliability-related services~~ necessary to meet its ~~r~~Reactive ~~p~~Power requirements to maintain ~~t~~Transmission voltage within operating limits, and deploys these as its set of Interconnected Operations Services~~reliability-related services~~.
- The Reliability Coordinator, working with the Transmission Operator, determines the need for black start~~Black Start~~ capacity. The Transmission Operator cannot do this alone, because it may not have a wide enough picture of the ~~t~~Transmission system.

~~Through its Reliability Standards, NERC holds organizations (those registered as Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Service Providers) responsible to comply with applicable standards requirements, including those requirements that depend on reliability-related services.~~ The quantity of and processes used to deploy those Interconnected Operations Services ~~reliability-related services~~ depend on the ~~R~~regional and local system characteristics and regulatory requirements. The responsible organizations establish the quality and quantity of their own Interconnected Operations Services ~~reliability-related services~~, using these processes and procedures in a manner that ensures reliable operation of the BES~~compliance with the standards' requirements~~.

~~Part 6 - Managing Bilateral Interchange Transactions – Basic Concepts~~

~~Interchange that crosses multiple Balancing Authority (BA) Areas can be broken down daisy-chain fashion into individual Balancing Authority to Balancing Authority Interchange Transactions, with the Sink Balancing Authority designated as the "manager" (the "Tag Authority").~~

~~The Functional Model recognizes this Interchange process as the current Industry practice and includes BA to BA "after hour" checkout for net Interchange between adjacent Balancing Authorities. Also, the Interchange Coordinator function "coordinates" and "communicates Interchange ("deals") that is ready for physical implementation between Balancing Authorities. The IC receives approvals that recognize ramping capability. The IC also communicates the individual Interchange information to all involved parties (Figure 6).~~

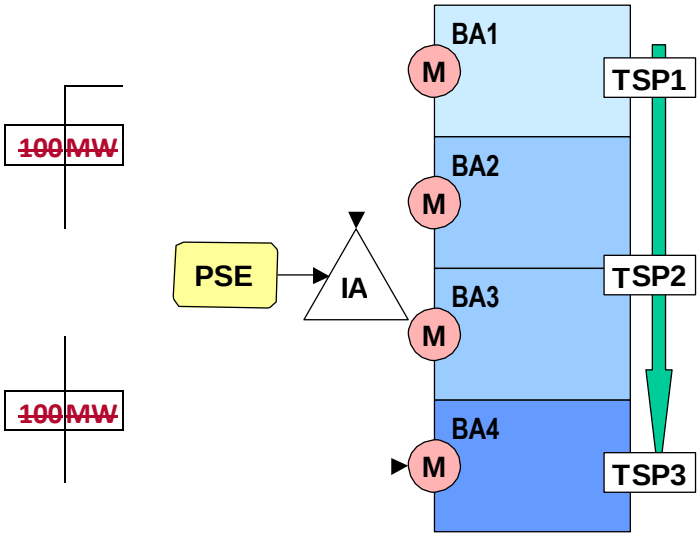


Figure 6 — The Interchange Coordinator manages transactions between the source and sink Balancing Authorities.

Managing Bilateral Interchange Transactions — Allowable Concept

The Functional Model does not prevent Balancing Authorities from scheduling Interchange with Interchange Coordinators. The ICs would ensure that the Arranged Interchange is balanced (equal and opposite) between the Source and Sink BAs. In the example in Figure 6, the IC manages a transaction from BA1 to BA4. The schedule is

BA1 → IA → BA4

and the transmission service path is

TSP1 → TSP2 → TSP3.

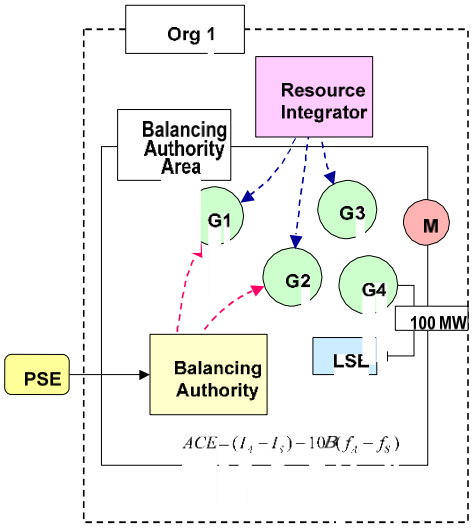


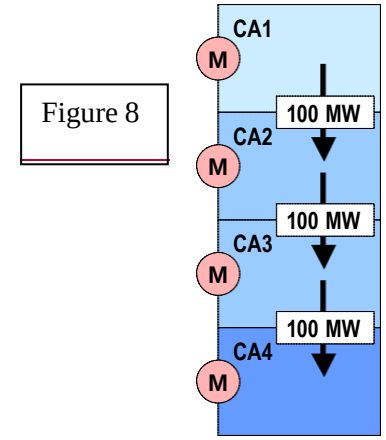
Figure 7 – The Purchasing-Selling Entity submits the bilatera transaction to the Balancing Authority for intra-BA transactions.

~~**Interchange Transactions within a Balancing Authority Area.** A bilateral Interchange within a Balancing Authority Area does not require Interchange Coordinator authorization. In the example in Figures 8 and 9, the Purchasing-Selling Entity submits the 100 MW request for Interchange to the Balancing Authority who will inform the Resource Integrator (or Market Operator) if the Resource Integrator needs to know which generators are committed to the Interchange, and to the Reliability Coordinator for reliability assessment.~~

~~The tables on the following page compare the Interchange checkout procedures that the Balancing Authorities use today with the procedures that the Balancing Authorities would use if this type of Interchange concept were applied.~~

Checkout under Existing NERC Practice Figure 8			
Control Area	**Actual from Tie Meters**	**Schedule with CA**	**Inadvertent**
CA1	+100 to CA2	+100 to CA2	0
CA2	-100 from CA1 +100 to CA3	-100 from CA1 +100 to CA3	0
CA3	-100 from CA2 +100 to CA4	-100 from CA2 +100 to CA4	0
CA4	-100 from CA3	-100 from CA3	0
Potential Future Checkout Figure 9			
Balancing Authority	**Actual from Tie Meters**	**Schedule with IC**	**Inadvertent**
BA1	+100 to BA2	+100 to IC	0
BA2	-100 from BA1 +100 to BA3	0	0
BA3	-100 from BA2 +100 to BA4	0	0
BA4	-100 from BA3	-100 from IC	0

Figure 8



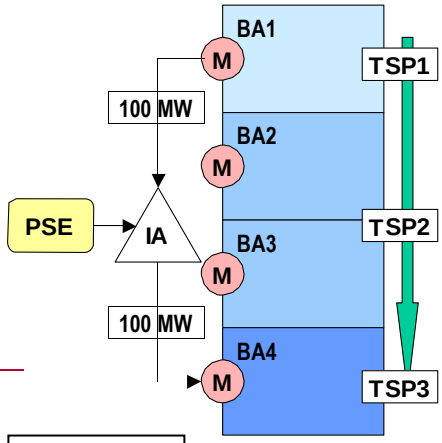


Figure 9

Part 7 - Managing Bilateral Interchange – Scheduling Agents

Some Transmission Providers provide a Scheduling Agent service for their Balancing Authority members. The Scheduling Agent provides a single point of contact for all Interchange into or out of those Balancing Authorities. For example, the Southwest Power Pool serves as a Scheduling Agent for its members, and any Balancing Authority external to SPP will schedule to any SPP Balancing Authority by way of the SPP as the Scheduling Agent. This simplifies Interchange scheduling for parties both internal and external to SPP.

In the example in Figure 10, two Interchange Coordinators arrange a total of 225 MW with the Scheduling Agent for a group of four Balancing Authorities as follows:

IS1 = 100 MW into BA1 IS3

= 50 MW into BA3 IS4 = 75

MW into BA4 IS2 = 0

The Scheduling Agent must ensure that the sum of the Interchange from all Interchange Coordinators is exactly equal to the sum of the Interchange from the Scheduling Agent to its Balancing Authorities:

ISA1 + ISA2 = IS1 + IS2 + IS3 + IS4

$I_{S1} + I_{S2} + I_{S3} + I_{S4} = 225$ MW

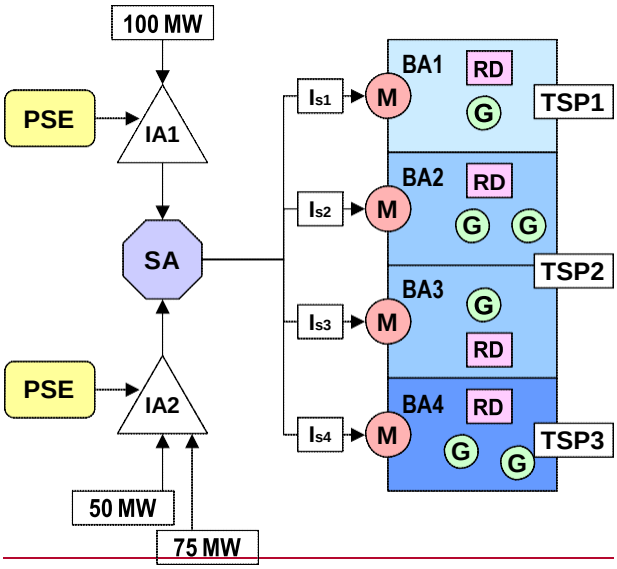


Figure 10 - The Scheduling Agent divides a 100 MW transaction among a group of Balancing Authorities.

If the Balancing Authority(ies) use a Scheduling Agent, then the Interchange Coordinator will request approvals from the Scheduling Agent — not the Balancing Authority(ies) — during the Interchange authorization process. The Interchange Coordinator will also notify the Scheduling Agent of any Interchange curtailments.

Because Interchange scheduling is an integral function of the Balancing Authority, the Functional Model Working Group defines that the Scheduling Agent is actually an agent of the Balancing Authorities. The Balancing Authorities would still be the Responsible Entities for ensuring that the Interchange from the Scheduling Agent was incorporated into the BAs' energy management systems. Some have argued that the Scheduling Agent would need to be certified and monitored to ensure that it handled the Interchange properly.

~~Part 8 – Non-coincident Resource Integrator and Balancing Authority Areas~~

~~**Bilaterals between Market Areas.** In the examples above, each Balancing Authority Area was the same as the Market or Resource Integrator Area. When generation is dispatched (either cost-based or bid-based) over several Balancing Authority Areas, we may be faced with a bilateral Interchange whose source or sink is the entire Market Area, and cannot be identified with any particular Balancing Authority within that area. In this situation, the Interchange Coordinator interfaces with the Scheduling Agent for the Market Area. Then the Scheduling Agent, working with the Market Operator will determine how the bilateral Interchange is allocated among the Balancing Authority Areas.~~

~~As was explained in the technical discussion on reliability related services, the Scheduling Agent ensures that the RDIS are properly allocated to the Balancing Authorities.~~

~~Now we can combine the Scheduling Agent's management of RDIS with bilateral Interchange Transactions as shown in Figure 11.~~

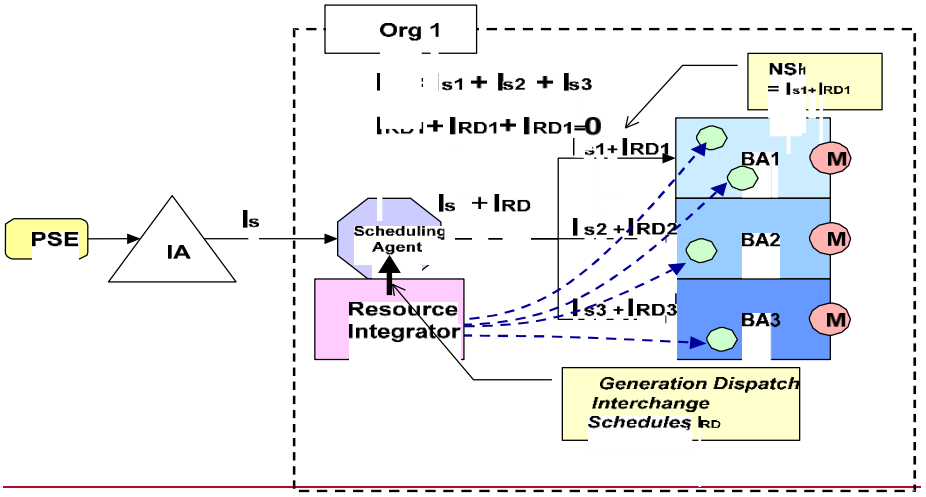
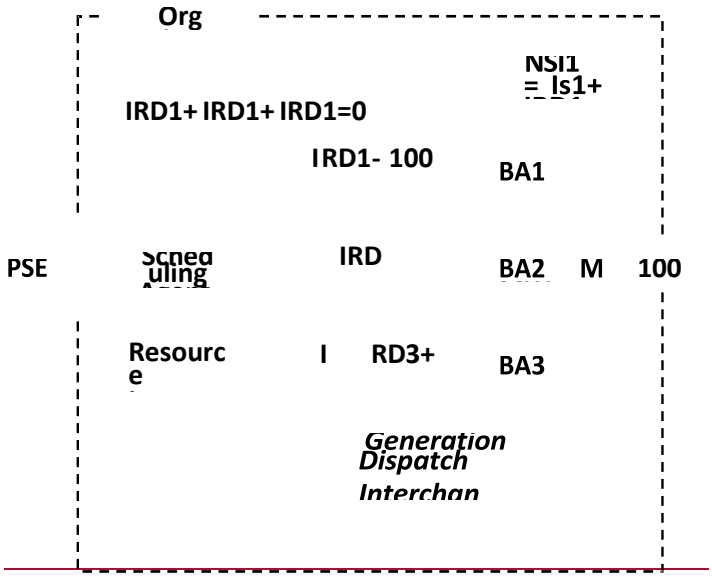


Figure 11 - The Scheduling Agent manages bilateral Interchange Transactions in to or out of the Market Area ~~as well as the Interchange Schedules that result from the~~ economic dispatch or market operations.

~~**Bilaterals between Balancing Authorities within the same Market Area**. Bilateral Interchange between two Balancing Authorities within the same Market Area does not require Interchange Coordinator management because the Market Area is under a common tariff, and the Market Operator would have a close relationship with the Reliability Coordinator. In the example in Figure 12 the Purchasing Selling Entity has submitted a 100 MW request for Interchange from BA1 to BA3 directly to the Scheduling Agent, who would then coordinate the transaction between the source and sink Balancing Authorities. The Scheduling Agent then submits the resulting interchange schedule to the Source and Sink Balancing Authorities, and informs the Market Operator if the Market Operator needs to know which generators are committed to the transaction.~~



~~*Figure 12 - The PSE submits its Interchange Transaction information directly to the Scheduling Agent when the bilateral transaction is within the same Market Area.*~~

Part 39 – Implementing Interchange Coordination

Requests for Interchange (RFI) are initiated by entities (Purchasing-Selling Entities, Load-Serving Entities, or Generator Owners) who have arranged for Interchange and contracted for Transmission Service from a Transmission Service Provider. The RFIs are submitted to a (Tag) agent service who confirms all information needed and electronically sends Tags to the authority service, or the Interchange Coordinator. The Interchange Coordinator IC Ttasks are being performed by the organization functional entities registered as Balancing Authorities (BAs), specifically the Sink Balancing Authority"sink BA"[8] for a particular interchange transaction. A Sink Balancing Authority is defined as, "[the Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule."[9] It has been noted that the Functional Model could in principle have assigned the IC Tasks to the BA and avoided the need for a separate Interchange function. This approach was not followed because it was envisioned in the future that the IC Tasks could be performed by entities other than a BA, a possibility that is allowed for by defining the IC separate from the BA. Therefore, the Functional Model *accommodates* the sink BA as the IC, but does not *require* it.

The implementation of the IC extends also to the NERC INT standards that exist today, which impose data collecting and interchange-information distribution requirements on an IC.

The NERC direction regarding registering of ICs is compatible with the approach taken in the Model:

- There is a need for a separate Interchange Coordinator functional entity
- Allowance is made for BAs to register as ICs, but organizations that are not BAs are not precluded from doing so.
- The IC is an entity, not a software tool.

The remainder of this section clarifies the context and need for an Interchange Coordinator from the perspective of the Model, by describing the associated reliability tasks and their implications. As such, it may be of use to those involved in registration processes.

INTERCHANGE PRACTICE

Background

To help ensure reliability, "requests" for iInterchange tTransactions (Arranged Interchange) must be approved before that request is allowed to become an "iImplemented" Iinterchange transaction (or Confirmed Interchange). Without approvals, it is possible that the sum of all iInterchange sSchedules in an interconnection will not sum to zero. That, in turn, would lead to the condition that even if every Balancing Authority were controlling to zero Area Control Error, there could still be off-generation occurring because of the Net Interchange sSchedule being in error.

Historically, approvals were handled on a control area to control area basis. Net iInterchange sSchedules between neighbors were checked and approved prior to implementation. Only if there were disagreements did individual requests get checked. This pragmatic practice served the industry well — but not perfectly. When given control areas did not take the time to compute their own Net Schedule interchange (and instead merely accepted the numbers from its individual neighbors) — what can and did happen was that individual

[8] That is, the BA in whose area the bilateral interchange transaction terminates.

[9] Definition of Sink Balancing Authority from the NERC Glossary of Terms (as of Mary 15, 2016).

schedules were active on one side of the control area, but not on the other side. Not until serious operational symptoms arose (*e.g.*, unexplained parallel flows, or unusual number of time error corrections) was there an investigation.

Current Practice

The ~~Functional Model's~~ inclusion of an Interchange Coordinator in the Functional Model recognizes a reliability concern regarding responsibility for approving a ~~r~~Request for ~~i~~Interchange, and the distribution of the information for the approved request for ~~i~~Interchange. Each and every Interchange ~~t~~Transaction that a Purchasing-Selling Entity~~SE~~ desires to implement must have approvals from all parties involved, and must have approval by each of them regarding the characteristics of each of those Interchange ~~t~~Transactions.

Today, the approval and communication are implemented in a two-step process — each step focusing on different quantities. One step focuses on the individual Interchange ~~t~~Transactions and their respective characteristics. This step is carried out by a tagging authority, which is the Interchange Coordinator. In order to obtain approval or denial, the Interchange Coordinator sends the Request for Interchange electronically, as Arranged Interchange, to the (tag) approval service provider for the Balancing Authorities, Transmission Service Providers, Load-Serving Entities, Purchasing-Selling Entities, and Generator Owners. After obtaining approval or denial, the approval service then sends the decision to the Interchange Coordinator. If all parties approve the Interchange Transaction, the Arranged Interchange becomes Confirmed Interchange. The Interchange Coordinator then informs all parties of this status.

The other step focuses on implementing Net Interchange ~~s~~Schedules (*i.e.*, the net of the ~~t~~Transactions that were approved). This step is carried out by neighboring Balancing Authorities~~As~~. The Sink Balancing Authority is responsible for ensuring the process is properly carried out. ~~This two-step process can and does work. The problem is that when there is a breakdown in the process, there is no compliance process in place.~~

~~For example, if the tagging authority were the root cause of non-compliance (such as a computer error) that caused transaction information to elude analysis of a participant in the transaction, and that error resulted in a blackout, then no one would be held non-compliant, if no entity is registered as IC for the transaction. If a BAleft accepts a Net Schedule from BAcenter but the transactions within that Net do not agree with the complementary transactions of the accepted Net Schedule between BAcenter and BAright, then again no one can be held non-compliant if no one is registered as IC.~~

~~What is in place t~~Today ~~is~~ the NAESB ~~NERC~~ Tagging Specification is in place. ~~,~~ Under the NAESB Tagging Specification, ~~under which~~ each ~~s~~Sink Balancing Authority is responsible for providing ~~T~~ttagging ~~S~~sservices, either directly or by arranging with a third party to provide this service as its agent.[10] ~~However, the Tagging Specification is not a standard and therefore not a sufficient basis for compliance enforcement.~~

~~An important question for many within industry is "how do you implement the concept of an Interchange Coordinator (IC)".~~

~~The initial step of the implementation requirements has been met with the NERC Board adoption of the Version 1 Interchange standards, which contain concepts and functions of the IA (now referred to as the IC). The Electronic Tagging Function Specification assigns the Tag Authority requirements to the entity responsible for Balancing Authority operations (*i.e.*, Sink BA).~~

[10] See, NAESB Electronic Tagging Functional Specification, version 1.8.0, approved November 7, 2007. Click here: http://reg.tsin.com/Tagging/e-tag/e-tag-spec-v-18-20071107.doc

~~To implement this concept, the Electronic Tagging Functional Specification (E-tag Spec.) was revised to map the Tagging Service requirement from the Balancing Authority to the entity performing the Interchange function for the Sink Balancing Authority's organization (still allows the Sink BA to use third party to fulfill the tasks of the requirements).~~

Part ~~10~~ 4 - ~~Distribution Provider as Load-Serving Entity~~ Risk-Based Registration

In support of its mission to assure the reliability of the Bulk Power System, NERC has transformed its approach to compliance and enforcement to be forward-looking with a focus on high reliability risk areas. The purpose of the NERC Risk-Based Registration (RBR) initiative was to ensure that the right entities are subject to the right set of applicable Reliability Standards, using a consistent approach to risk assessment and registration. In December 2014, NERC submitted a petition for approval of proposed revisions to the NERC Rules of Procedure (ROP), seeking to implement the changes sought as a result of the RBR initiative.[11] Specifically, NERC requested major reforms to the registration process, including the elimination of the Purchasing-Selling Entity (PSE), Interchange Authority (IA), and Load-Serving Entity (LSE) functional registration categories; modifications to the thresholds for registering entities as Distribution Providers (DP); and procedural improvements to the registration process. The procedural improvements to the registration process included: (1) the establishment of a materiality test for registration, with clear procedures and criteria for evaluation of whether an entity has a material impact on reliability with respect to above-the-line and below-the-line Registry Criteria determinations; (2) an enhanced process for review by a NERC-led, multi-regional panel of certain registration, deactivation and deregistration decisions, as well as certain requests for sub-set lists of Reliability Standards; (3) development of a common registration form to facilitate uniformity in Regional Entity collection of the information from registration candidates; and (4) one-time attestations that allow entities to record that a specific Reliability Standard requirement is "Not Applicable." On March 19, 2015, the Commission issued an order largely approving proposed revisions to the NERC ROP.[12]

As outlined in the RBR petition, the ERO compliance program and stakeholders benefit from the proposed revisions as they appropriately focus resources on entities with the greater potential impact on reliability. The RBR reforms were based on the February 2011 Commission technical conference in Docket No. AD11-6-000 on *Priorities for Addressing Risks to the Reliability of the Bulk-Power System*, where there was a recognition that "if everything is a priority, then nothing is a priority."[13] Priorities must be driven by a clear understanding of risks and consequences, and the costs and benefits associated with addressing them. With a shift toward risk-based approaches and a learning industry, NERC introduced quantitative measures of reliability performance. The revisions were a result of NERC taking a risk-based approach to reliability and to incorporating lessons-learned through continuously improving and adapting operations.

Even though the three entities (PSE, IA, and LSE) were removed from the NERC Registry Criteria, these entities–as users, owners and operators of the Bulk Power System–remain within in the statutory scope of both FERC and NERC pursuant to Section 215 of the Federal Power Act. Functionally, Load-Serving Entities, Purchasing-Selling Entities and Interchange Authorities continue to exist and continue to perform in the markets or operate under open access transmission tariffs, as applicable. The revisions did not alter the NERC registered ballot body (codified in Appendix 3D of the NERC Rules of Procedure).

~~FERC Order of October 16, 2008 approved a NERC filing that proposed, as a short-term solution, revisions to the NERC Statement of Compliance Registry Criteria (Registry Criteria) to provide that a distribution provider to~~

[11] See, Petition of the North American Electric Reliability Corporation for Approval of Risk-Based Registration Initiative Rules of Procedure Revisions, Docket No. RR15-4-000 (2014).

[12] North American Electric Reliability Corporation, 150 FERC ¶ 61,213 (2015).

[13] Additional information available on FERC website: http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=5561&CalType=%20&CalendarID=116&Date=02/08/2011&View=Listview.

whose system the electric loads in retail choice areas are connected will be registered as the LSE for all loads connected to its system.[14]

The Order requires that "the Distribution Provider to whose system the electric loads in retail choice areas are connected are to be registered as the LSE for all loads connected to its system for the purpose of compliance with NERC's approved reliability standards applicable to LSEs."

NERC states that, with respect to load served by retail choice through load aggregators, there may not be a clear agreement in place between the distribution providers and the load aggregators delineating the responsibilities between the parties regarding compliance with mandatory Reliability Standards. Further, the compliance filing explains that "NERC will exercise its discretion in the application of penalties or sanctions upon Distribution Providers who are providing this information on the behalf of loads served by a retail choice load aggregator until such time as both entities are either registered or the standards are updated to clarify the responsibilities for each party as ultimately identified in the longer term solution proposed by NERC."

NERC stated that DPs have both the infrastructure and access to information to enable them to comply with the Reliability Standards that apply to LSEs. Moreover, distribution providers provide the wires over which the load of retail power marketers is served. NERC also pointed out that, with regard to distribution providers that provide wires service for retail power marketers, these DPs were LSEs for that load prior to state retail access programs. In many instances, these distribution providers remain providers of last resort and must plan their system taking into consideration all load served over their wires, including retail access load.

The Order also provides that a distribution provider will not be registered based on the above criterion if it has transferred responsibility to another entity (that is appropriately registered) by written agreement.

NERC also stated that this approach ensures that all loads are represented in the planning and operation of the Bulk Power System by the entity with the best information regarding those loads.

The scope of the review leading to Version 5 of the Functional Model included consideration of whether changes should be made in the Model to accommodate these changes to the Registry Criteria.

Version 5 does *not* contain changes to reflect these changes to the Registry Criteria, as follows:

- the problem and its solution relate to registration, not the Tasks performed, and as such do not directly affect the Model; this is in keeping with the approach used for the Joint Registration Organization, which is defined for compliance purposes and not in the Model
- the present solution is a short-term one, with the longer-term solution yet to be defined.

[14] This section contains extracts from the order, which may be found at http://www.nerc.com/files/Statement_Compliance_Registry_Criteria_V5-0.pdf

Part 11 – Terminology Changes in Version 5

Version 5 contains terminology changes intended to improve consistency between the Model and the NERC Glossary, the Rules of Procedure (ROP) and Reliability Standards.[15] Inconsistency has potential for creating needless complexity, confusion and wasted effort for those who use NERC documents. The changes are of three types:

- Entity terminology
- Entity names
- Entity definitions. Entity terminology

The term "responsible entity" in the Model has been changed to "functional entity".[16]

- The usage of "responsible" in Version 4 derived from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" in the Model.
- The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities. Consistency within NERC documents would be improved if conforming changes were made to the NERC Rules of Procedure and Glossary of Terms to consistently use the term "functional entity" when the reference is to the *class of entity* (*e.g.*, BA), and use the terms "responsible entity" and "registered entity" when the reference is to a *specific organization* regarding its responsibility or registration, respectively.[17]

Entity names

- The functional entity name Interchange Authority has been changed to Interchange Coordinator
  - The term "coordinator" better reflects the nature of the function.
  - A conforming change would be required in the Glossary (which also uses Interchange Authority)
- Conforming changes would be required in other NERC documents.

Entity definitions

- The Model has been revised to define the various functional entities, not the Functions as at present, consistent with the approach used in the Glossary and standards.
- The functional entity definitions have been revised.
  - The form of the definitions is uniform, with each definition beginning: "The functional entity …"
  - Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.

[15] Full alignment will require conforming changes in Reliability Standards, the Glossary and ROP. These changes are seen as editorial that is, not representing changes to essential content.

[16] Version 4 actually uses "Responsible Entity". Because the Glossary and ROP generally use "responsible entity", *i.e.*, all lower case, this usage has been adopted for version 5 of the Model.

[17] These changes in terminology are intended to address confusion between the entity described in the Model and specific organizations, which has been a frequently expressed concern of stakeholders.

The following table gives the Version 4 definitions, the Glossary definitions (April 20, 2009), and the Version 5 definitions (recommended for use in the Glossary.

Functional Entity Definitions:

Model Version 4, NERC Glossary and Model Version 5

VERSION 4[18]	GLOSSARY[19]	VERSION 5[20]	COMMENT
Balancing Authority	**Balancing Authority**	**Balancing Authority**	
Integrates resource plans ahead of time, and maintains load-interchange- generation balance within a Balancing Authority Area and supports Interconnection frequency in real time.	The responsible entity that integrates resource ahead of time, maintains load- interchange-generation balance within a Balancing Authority Area, and supports Interconnection	The functional entity that integrates resource plans ahead of time, maintains generation-load-interchange balance within a Balancing Authority Area, and contributes to Interconnection frequency	Minor Glossary change needed.
Compliance Enforcement Authority	**Compliance Monitor**	**Compliance Enforcement Authority**	
Monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-compliance to the standards.	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.	The functional entity that monitors, reviews, and ensures compliance with Reliability Standards and administers sanctions or penalties for non-	Glossary needs to be updated
Distribution Provider	**Distribution Provider**	**Distribution Provider**	

[18] For simplicity of presentation, the definitions indicated for the Model in Version 4 are assigned to the functional entity, not the function. For example, the Model has a definition for the Standards Development function, but the definition is shown below as applying to the Standards Developer *functional entity*.

[19] Glossary version of February 12, 2008. See link at http://www.nerc.com/files/Glossary_12Feb08.pdf

[20] These definitions would replace existing definitions in the Glossary (but entities not currently defined in the Glossary would not be added).

VERSION 4	GLOSSARY	VERSION 5	COMMENT
Provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.	The functional entity that provides facilities that interconnect an End-use Customer load and the electric system for the transfer of electrical energy to the End-use Customer.	Glossary change needed – descriptive detail removed. Revised version would be essentially that of Version 4 of the Model.
Generator Operator	**Generator Operator**	**Generator Operator**	
Operates generating unit(s) to provide real and reactive power.	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.	The functional entity that operates generating unit(s) and performs the functions of supplying energy and reliability-related services.	Minor Glossary change needed.
Generator Owner	**Generator Owner**	**Generator Owner**	
Owns and provides for maintenance of generating facilities.	Entity that owns and maintains generating units.	The functional entity that owns and maintains generating	Minor Glossary change needed.
Interchange Coordinator	**Interchange Authority**	**Interchange Coordinator**	
Ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Arranged Interchange between Balancing Authority Areas.	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.	The functional entity that ensures communication of Arranged Interchange for reliability evaluation purposes and coordinates implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas.	Glossary changed needed. Revised version would be essentially that of Version 4 of the Model.
Load-Serving Entity	**Load-Serving Entity**	**Load-Serving Entity**	

~~Secures capacity, energy and transmission services (including necessary reliability-related services) to serve the End-use Customer.~~	~~Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of~~	~~The functional entity that secures energy and transmission services (and reliability-related services) to serve the electrical demand and energy~~	~~Minor Glossary change needed.~~

VERSION 4	GLOSSARY	VERSION 5	COMMENT
	its end-use customers.	requirements of its end-use customers.	
Market Operator (Resource Integrator)	[not defined]	**Market Operator (Resource Integrator)**	
The Market Operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability Functions with		The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.	Term not used in Reliability Standards and therefore is not required in the Glossary..
Purchasing Selling Entity	**Purchasing Selling Entity**	**Purchasing Selling Entity**	
Purchases or sells energy, capacity, and necessary reliability-related services as required.	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.	The functional entity that purchases or sells, and takes title to, energy, capacity, and reliability related services.	Glossary change needed – descriptive detail removed.
Planning Coordinator	**Planning Authority / Coordinator**	**Planning Coordinator**	
Ensures a plan (generally one year and beyond) is available for adequate resources and transmission within a Planning Coordinator area. It integrates and evaluates the plans from the Transmission Planners and Resource Planners within the Planning Coordinator area to ensure those plans	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.	The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas	Minor Glossary changed needed.
Reliability Assurer	[not defined]	**Reliability Assurer**	

Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to		The functional entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of	Term not used in Reliability Standards and therefore is not required in the Glossary.

VERSION 4	GLOSSARY	VERSION 5	COMMENT
secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.		functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer Area and adjacent areas.	
Reliability Coordinator	**Reliability Coordinator**	**Reliability Coordinator**	
Ensures the real-time operating reliability of the bulk power system within a Reliability Coordinator Area.	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.	The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.	Glossary changed – descriptive detail removed. Revised version would be essentially that of Version 4 of the Model.

Resource Planner	**Resource Planner**	**Resource Planner**	
Develops a plan (generally one year and beyond) within its portion of a Planning Coordinator area for the resource adequacy of its specific loads (End-use Customer demand and energy requirements) within a reliability area.	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy [of] specific loads (customer demand and energy requirements) within a Planning Authority Area.	The functional entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Resource Planner area.	Minor Glossary change needed.
Standards Developer	[not defined]	**Standards Developer**	

VERSION 4	GLOSSARY	VERSION 5	COMMENT
Develops and maintains Reliability Standards to ensure the reliability of the bulk power system.		The functional entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.	Term not used in Reliability Standards and therefore is not required in the Glossary.
Transmission Operator	**Transmission Operator**	**Transmission Operator**	
Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.	The functional entity that ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.	Glossary changed needed. Revised version would be essentially that of Version 4 of the Model.
Transmission Owner	**Transmission Owner**	**Transmission Owner**	
Owns and provides for the maintenance of transmission facilities.	The entity that owns and maintains transmission facilities.	The functional entity that owns and maintains transmission facilities.	Minor Glossary change needed.

~~Transmission Planner~~	~~Transmission Planner~~	~~Transmission Planner~~	
~~Develops a plan (generally one year and beyond) for the reliability of the interconnected bulk power system within the Transmission Planner Area. Ensures that the plan integrates resources and transmission within its area as well as coordinating with the plans from adjacent and overlapping Transmission Planners and Resource Planners. The Transmission Planner also ensures that the plan meets the Reliability Standards.~~	~~The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.~~	~~The functional entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner Area.~~	~~Minor Glossary change needed.~~
~~Transmission Service Provider~~	~~Transmission Service Provider~~	~~Transmission Service Provider~~	
~~Administers the transmission tariff and provides transmission services under applicable transmission service agreements (for example, the pro forma tariff).~~	~~The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.~~	~~The functional entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.~~	~~Minor Glossary change needed.~~

Part 512 - ~~Reliability~~ Areas and Boundaries

~~**Assets versus Geography as the Basis for Defining Areas and Boundaries**~~

~~It is useful for organizations that are functional entities to specify an associated Area, which defines the portion of the Bulk Electric System within which their functional entity status applies. Moreover, by reviewing all of the Areas for a particular functional entity, it is possible to establish whether there are overlapping responsibilities or gaps, which can then be eliminated. The concept of Areas and boundaries (the interfaces between adjacent Areas) is therefore important in establishing clear responsibilities for compliance with Reliability Standards.~~

The ~~Functional Model~~ building block for defining boundaries and ~~A~~areas for the functional entities that operate and plan the Bulk Electric System is electrical, namely the individual Bulk Electric System asset. That is, the building blocks are the individual ~~t~~Transmission, generation and customer equipment assets that collectively constitute the Bulk Electric System. This enables any given Bulk Electric System asset to be associated with at least one ~~single organization, with respect to any particular~~ functional entity. This will ~~therefore~~ provide the basis for clear assignment of responsibility for managing the potential reliability impacts of the asset~~., where the specific responsibility is to be established in NERC's registration, certification and compliance processes.~~

~~It is noted that a~~ A geographic definition is not ~~adequate~~ appropriate in a situation where there are, for example, two Transmission Operators in a given geographic footprint, differentiated by the voltage level of the assets under their respective control. In such a situation, the use of the specific Bulk Electric System assets provides an adequate basis for defining Areas/boundaries.

The following areas and boundaries are essential for understanding how to reliably operate and plan for a particular BES asset:

1. **Reliability Coordinator Area**: The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
2. **Balancing Authority Area**: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
3. **Transmission Operator Area**: The collection of Transmission assets over which the Transmission Operator is responsible for operating.

~~1.~~4. **Transmission Planner area**: The collection of Transmission assets over which the Transmission Planner is responsible for planning.

~~2.~~5. **Planning Coordinator area**: The collection of Transmission assets over which the Planning Coordinator is responsible for coordinating planning. Its area includes one or more Transmission Planner Areas.

~~NERC Rules of Procedure specify area relationships among functional entities, excerpted as follows:~~

~~2.2 Regional entities shall verify that all balancing authorities and transmission operators are under the responsibility of one and only one reliability coordinator.~~

~~2.3 Regional entities shall verify that all transmission elements of the bulk power system operated within their geographic boundaries are under the authority and control of one and only one transmission planner, planning authority, transmission owner, and transmission operator.~~

~~2.4 Regional entities shall verify that all loads and generation sources within their geographic boundaries are under the authority and control of one and only one balancing authority.~~

~~2.5 Regional entities shall verify that no geographical or electrical areas of the bulk power system within their boundaries have duplication of coverage or are lacking an entity to perform required duties and tasks as identified in the reliability standards.~~

~~Size Considerations Relating to Area~~

~~The Functional Model does not specify a minimum or maximum size for a reliability area. From the perspective of the Model, an organization qualifies to be the Responsible Entity for a particular Function by virtue of performing the Function's Tasks.~~

~~Size is not a consideration in the distinction between local-area versus wide-area reliability. Local-area reliability is the responsibility of the Transmission Operator in the sense of considerations relating to the Transmission Operator's local system or area, regardless of how large that area may be. Similarly, wide-area reliability is the responsibility of the Reliability Coordinator in the sense of considerations relating as well to the systems and areas of neighboring Reliability Coordinators, regardless of how small the Reliability Coordinator's own area may be.~~

~~Part 13 – Generating versus Transmission Assets~~

~~The Model does not attempt to define the boundary between generating and transmission facilities, in particular regarding facilities such as protective relays and lines that are within or in proximity to a generating plant perimeter. Such boundaries may be defined by NERC, Regional Entities or governmental authorities.~~

~~From the perspective of the Model, for a facility that is determined to be a generating facility, its owner will be a Generator Owner, and its operator a Generator Operator. Correspondingly, for a facility that is determined to be a transmission facility, its owner will be a Transmission Owner, and its operator a Transmission Operator.~~

~~It is recognized that an owner may not be the operator of its facility, as a result of delegating the operating of the facility to another party through an agreement, and that in all cases it is NERC's registration process, not the Model that determines assignment as a functional entity.~~

~~Part 14 – Roles in Load Curtailment~~

~~This section discusses the roles of the various functional entities that may be involved in load curtailment. These entities include: Reliability Coordinator, Balancing Authority, Transmission Operator, Distribution Provider and Load-Serving Entity.~~

~~Types of Load Curtailment~~

~~There are two general types of load curtailment — voluntary and non-voluntary.~~

~~A. Voluntary Load Curtailment~~

~~Voluntary load curtailments are usually arranged ahead of real time under some form of agreements — market price trigger, compensation, etc., or on a totally voluntary basis with or without any compensation. Implementation of voluntary load curtailment is intended to provide a relief to the market price in some established markets, or a relief to system demand to aid the Balancing Authority in a tight capacity/energy situation, or a relief to loading on a Distribution Provider system.~~

~~Voluntary load curtailment based on pricing structure need not be requested since it is governed by pre-arranged agreement and mechanism. Voluntary curtailments that have not been pre-arranged may need to be communicated. Since end-use customers are involved in the decision-making process and must respond to the request, and the Load-Serving Entity holds the contractual obligation to serve these customers, such requests are usually communicated to the end-use customers through the Load-Serving Entity as directed by the initiating entities, which include the Balancing Authority and the Distribution Provider, to address potential capacity/energy shortfall in the Balancing Authority area or potential overload on the Distribution Provider system.~~

~~B. Non-Voluntary Load Curtailment (Shedding)~~

~~Non-voluntary load curtailments are usually implemented in real time to address imminent or existing capacity/energy shortfalls or transmission reliability concerns such as exceedance of an IROL or SOL, or a low voltage problem. Some pre-arrangements may be made ahead of time such as identifying the amount and location of load to be shed, and specific critical loads that may be excluded from curtailment by feeder configuration. However, since implementation is often of urgent nature, a decision process involving the end-use customers and communication via the Load-Serving Entity is usually bypassed.~~

~~Depending on the need to implement this type of curtailment, load is either curtailed automatically (such as in the case of underfrequency or undervoltage load shedding), or a curtailment directive is made by the Reliability Coordinator, Balancing Authority, or Transmission Operator directly to the Distribution Provider for physical implementation (except when this can be accomplished directly by the Transmission Operator). The Distribution Provider may also have a need to curtail load to address overload problems on its system. In this case, the Distribution Provider may implement load shedding directly.~~

Role of Responsible Entities in Load Curtailment Reliability

Coordinator

The Reliability Coordinator maintains Real-time system reliability, which includes implementing a number of emergency actions which include directing load shedding to preserve system reliability. In addition, the Reliability Coordinator, in collaboration with the Balancing Authority and Transmission Operator, may also participate in invoking public appeals, voltage reductions, demand-side management, and even load shedding if the Balancing Authority cannot achieve resource-demand balance.

When a Reliability Coordinator has a need to direct non-voluntary load curtailment, it issues a directive to the Distribution Provider or the Transmission Operator to implement the curtailment.

Balancing Authority

When a Balancing Authority anticipates or experiences a capacity or energy shortfall, it will take actions such as public appeals, demand-side management programs, and load curtailment, as necessary to maintain a resource/demand/interchange balance. As time permits, the Balancing Authority may seek voluntary load curtailment to reduce demand in its area. In this case, the Balancing Authority will communicate such a request to the Load-Serving Entity. In the event of an Energy Emergency, the Balancing Authority may direct non-voluntary load curtailment by issuing a directive to the Distribution Provider or the Transmission Operator for implementation.

Transmission Operator

The Transmission Operator, in coordination with the Reliability Coordinator, can take actions such as implementing voltage reductions and implement load shedding to mitigate a transmission emergency. When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedance of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.

Distribution Provider

The Distribution Provider provides the facilities that could be used to shed load for emergency action. It is that entity that has the capability to physically shed load, but it is generally not responsible for directing load shedding. Loading shedding is generally directed by the Reliability Coordinator, Balancing Authority and Transmission Operator.

However, the Distribution Provide may itself initiate voluntary and non-voluntary load curtailments for its own reasons, for example to reduce its area's demand or to mitigate overload on its system. When a Distribution Provider sees a need for voluntary load curtailment, it directs the Load-Serving Entity to communicate a request for curtailment to the end-use customers.

When it sees a need to implement non-voluntary load curtailment to address a loading or voltage concern, it implements the curtailment on its own.

Load-Serving Entity

The Load-Serving Entity identifies the loads for voluntary as well as non-voluntary curtailments. For voluntary load shedding, the LSE is responsible for making contractual arrangements with end-use customers who participate in such a program, and identifying to the Balancing Authorities and Distribution Providers of such arrangements so

~~that these customers, once committed, would be put on curtailment list if and when needed to address potential capacity shortage and/or system constraints.~~

~~For voluntary load curtailment that has not been pre-arranged, the Load-Serving Entity may be directed by the Balancing Authority or Distribution Provider to communicate its curtailment requests to the end-use customers.~~

~~For non-voluntary curtailment, such as automatic underfrequency and undervoltage load shedding and manual load shedding, the Load-Serving Entity identifies which critical customer loads should be excluded from curtailment for public health, safety and/or security reasons.~~

~~Once identified and necessary contractual arrangements are made, the Distribution Provider (or the Transmission Operator as appropriate) will make reasonable efforts to arrange (feeder) connection arrangement such that these critical loads will not be curtailed by the load shedding facilities until other options have been exhausted.~~

~~The Load-Serving Entity is responsible for communicating requests for voluntary curtailment to the appropriate end-use customers, thereby increasing the effectiveness of voluntary load curtailment. In some jurisdictions, it appears that the "wires" entity, *i.e.*, the Distribution Provider, that performs these Tasks. However, from a functional model viewpoint, it is the Load- Serving Entity function within that Distribution Provider organization that performs this task.~~

Part 15 – History of Revisions

Version 1

Version 1 of the Model was approved in February 2002.

Version 2

Version 2 of the Model was approved Feb. 10, 2004.[21]

Version 2 responded to confusion between a Function and the organization responsibility for its performance, by separately identifying the Responsible Entity associated with each Function. For example, whereas Version 1 used the single term Transmission Operator for both the Function and responsible entity, Version 2 introduced Transmission Operations as the Function (the Tasks), and Transmission Operator as the Responsible Entity for those Tasks. Corresponding changes were made for all Functions. This distinction has been maintained in subsequent versions.

The Market Operation Function and Market Operator were added to the Model to provide an interface point with commercial functions.

Version 1 contained only operating Functions. Version 2 introduced three planning Functions (Planning Reliability, Transmission Planning, Resource Planning) and three associated Responsible Entities (Planning Authority, Transmission Planner and Resource Planner).

Version 3

Version 3 of the Model was approved February 13, 2007.[22] It addressed a number of issues that arose as NERC transitioned to new, mandatory and enforceable reliability standards. Several of these issues were outlined in a final report issued by the Functional Model-Reliability Standards Coordination Task Force (FMRSCTF) in March 2005.[23] The FMRSCTF was established to ensure alignment between the Model and the new NERC standards being developed.

The changes introduced in Version 3 included:

- The Reliability Authority entity name was changed to Reliability Coordinator, for consistency with terminology used in reliability standards.
- Changes were made to more clearly define the Transmission Operations Tasks and the relationship of the Transmission Operator with the Reliability Coordinator
- Changes were made to the Interchange Coordinator to accommodate the practice of Balancing Authority-to-Balancing Authority interchange scheduling
- The Planning Authority was renamed the Planning Coordinator
- The Regional Reliability Assurance Function and the Regional Reliability Organization Responsible Entity were added.
- It was clarified that "area" of responsibility for a particular Responsible Entity's applied to the collection of Bulk Electric System assets associated with the entity, that is, that area was defined electrically, not

[21] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Functional_Model_Version_2.pdf.
[22] See ftp://www.nerc.com/pub/sys/all_updl/oc/fmrtg/Function_Model_Version3_Board_Approved_13Feb07.pdf.
[23] Final Report of the Functional Model — Reliability Standards Coordination Task Force ("FMRSCTF"), approved March 11, 2005. See ftp://www.nerc.com/pub/sys/all_updl/sac/fmrsctf/FMRSC_TF_Report_3-11-05.pdf.

geographically.

Version 4

Version 4 included the following changes from Version 3:

- The names Regional Reliability Assurance / Regional Reliability Organization were changed to Reliability Assurance / Reliability Assurer.

  The name changes reflect the view that reliability assurance could be performed on other than a regional basis. Moreover, the functional entity need not be a Regional Entity.

- The names Compliance Monitoring / Compliance Monitor were changed to Compliance Enforcement / Compliance Enforcement Authority.

  The changes were judged to better reflect the strong role of compliance in the ERO regime.

- The wording was changed in a number of instances to ensure that the Model's Tasks and relationships between Responsible Entities do not specify prescriptive requirements. Prescriptive requirements are specified in reliability standards and NERC processes, not in the Model.

- For example, references in Version 2 that a Responsible Entity "must ensure" or "is required to ensure" were changed in Version 4 to simply "ensures".

- It was clarified that the Generator Owner and Transmission Owner *provide for the maintenance* of their respective assets.

  This recognizes that the performance of the maintenance may be assigned by the owner to another party, for example, to a Generator Operator or Transmission Operator, respectively.

Version 5

Version 5 introduces the following changes:

Entity name

- Interchange Authority has been changed to Interchange Coordinator. Also incorporated are the terms Arranged and Confirmed Interchange to be consistent with terminology used in the INT standards.

Terminology

The term "responsible entity" in the Model has been changed to "functional entity".

- The usage of "responsible" in Version 4 derived from an earlier version of the Model. Version 4 clarified that the Model is limited to describing the performance of tasks, but not compliance aspects such as responsibility for such performance. Version 5 takes this clarification one step further by replacing the term "responsible" in the Model.

- The Model uses the term functional entity to apply to a *class of entity*, such as a Balancing Authority, and makes no reference to the *specific organizations* that register as functional entities.
- Reliability is best served if there is consistency of definitions within all NERC documents. These documents include, but are not limited to, the Functional Model, the NERC Rules of Procedure and Glossary of Terms.

Entity definitions

- The Model has been revised to define the various *functional entities*, not the *functions*, consistent with the approach used in the Glossary and standards.
- The functional entity definitions have been revised.

- ~~The form of the definitions is uniform, with each definition beginning: "The functional entity that…"~~
- ~~Each definition is single sentence, limited to a simple statement of the nature of the tasks performed. As a result some of the current descriptive wording in Version 4 or Glossary definitions has been removed in the Version 5 definitions.~~

Standard Development Timeline

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

Description of Current Draft

EOP-004-4 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	07/25/2016 – 09/08/2016
45-day formal comment period with additional ballot	09/26/2016 – 11/09/2016
10-day final ballot	12/01/2016 – 12/12/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

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

A. Introduction

1. **Title:** Event Reporting

2. **Number:** EOP-004-4

3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-004-4.

~~**6. Background:** NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:~~

~~1. CIP-001 could be merged with EOP-004 to eliminate redundancies.~~
~~2. Acts of sabotage have to be reported to the DOE as part of EOP-004.~~
~~3. Specific references to the DOE form need to be eliminated.~~
~~4. EOP-004 had some 'fill-in-the-blank' components to eliminate.~~

~~The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.~~

~~The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the "road map" that will be used by the DSR SDT in~~

~~updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.~~

~~**7. Standard-Only Definition:** None~~

B. Requirements and Measures

~~**Rationale for Requirement R1:** Text~~

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-~~2 3~~ 4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-~~3~~4 Attachment 1 and in accordance with the entity responsible for reporting.

~~**Rationale for Requirement R2:** Text~~

R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday~~ local time~~). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event either a~~,~~ copy of the completed EOP-004-~~3~~ 4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM local time on Monday~~ local time~~). ~~(R2)~~

~~Rationale for Requirement R3:~~ ~~Text~~

~~**R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement~~s~~ R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement~~s~~ R2~~, R3~~ and Measure M2~~, M3~~.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

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

1.3. Compliance Monitoring and Enforcement Program

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

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.

R #	Violation Severity Levels			
				OR The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.
~~R3.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.~~ ~~OR~~ ~~The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.~~ ~~OR~~ ~~The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.~~ ~~OR~~ ~~The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.~~	~~The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.~~ ~~OR~~ ~~The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.~~

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: -systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Generation loss: The EOP SDT discussed dispersed power producing resources and their generation loss due to weather patterns or fuel source unavailability, but NERC confirmed that reporting of generation loss would be used to report Forced Outages not weather patterns or fuel source unavailability for these resources.

Complete loss of Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information."

Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of ~~a~~ its Facility	~~BA,~~ TO, ~~TOP,~~ GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to ~~a~~ its Facility	~~BA,~~ TO, ~~TOP,~~ GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at ~~a~~ its Facility. ~~Do not report theft unless it degrades normal operation of a Facility.~~
Physical threats to ~~a~~ its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at ~~a~~ its BES control center.
~~BES Emergency requiring public~~ Public appeal for load reduction	~~Initiating entity is responsible for reporting~~BA	~~Public appeal for load reduction event.~~Public appeal for load reduction to maintain continuity of the BES.
~~BES Emergency requiring system~~System-wide voltage reduction to maintain the continuity of the BES	~~Initiating entity is responsible for reporting~~TOP	System wide voltage reduction of 3% or more.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
~~BES Emergency requiring manual f~~Firm load shedding resulting from a BES Emergency	~~Initiating entity is responsible for reporting~~RC, BA, TOP	~~Manual firm~~ Firm load shedding ≥ 100 MW.
~~BES Emergency resulting in automatic firm load shedding~~	~~DP, TOP~~	~~Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).~~
BES Emergency resulting in ~~Voltage~~ voltage deviation on a Facility	TOP	~~Observed within its area a~~ A voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.
~~IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~	~~RC~~	~~Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).~~
Uncontrolled ~~Loss~~ loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled ~~Loss~~ loss of firm load for ≥ 15 Minutes from a single incident: ≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW OR ≥ 200 MW for all other entities

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA~~, GOP~~	Total generation loss, within one minute, of~~-~~: ≥ 2,000 MW ~~for entities~~ in the Eastern, ~~or~~ Western, or Quebec Interconnection OR ≥ 1,000 MW ~~for entities~~ in the ERCOT ~~or Quebec~~ Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of ~~voice communication~~Interpersonal Communication capability at a BES control center	RC, BA, TOP	Complete loss of ~~voice~~ Interpersonal ~~communication~~ Communication capability affecting a staffed BES control center for 30 continuous minutes or more.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of monitoring or control capability at a BES control center	RC, BA, TOP	Complete loss~~Complete loss~~ of monitoring or control at ~~capability affecting~~ a BES control center for 30 continuous minutes or more. ~~such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.~~

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task		**Comments**
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No☐ Unknown ☐
4.	**Event Identification and Description:**	

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."	
Task	**Comments**
(Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical Threat to ~~a~~ its Facility ☐ Physical Threat to ~~a~~ its BES control center ☐ Unplanned BES control center evacuation ☐ Public appeal for load reduction ☐ System-wide voltage reduction ☐ BES Emergency: ~~☐ public appeal for load reduction~~ ~~☐ system-wide voltage reduction~~ ☐ ~~manual~~ firm load shedding ☐ ~~automatic firm load shedding~~voltage deviation on a Facility ☐ uncontrolled loss of firm load ~~☐ Voltage deviation on a Facility~~ ~~☐ IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer~~	Written description (optional):

EOP-004 Attachment 2: Event Reporting Form Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780. Also submit to other organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."	
Task	**Comments**
~~Paths (WECC only)~~ ☐ ~~Loss of firm load~~ ☐ System separation ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ ~~unplanned~~ Unplanned BES control center evacuation ☐ Complete loss of ~~voice~~ Interpersonal ~~communication~~ Communication capability at a BES control center ☐ Complete loss of monitoring or control capability at a BES control center	

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	

Guideline and Technical Basis

~~**Distribution Provider Applicability Discussion**~~

~~The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the "Threshold for Reporting" for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more that 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.~~

Multiple Reports for a Single Organization

For entities that have multiple registrations, the ~~DSR SDT intends~~requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

~~**Summary of Key Concepts**~~

~~The DSR SDT identified the following principles to assist them in developing the standard:~~

- ~~Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System~~
- ~~Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements~~
- ~~Establish clear criteria for reporting~~
- ~~Establish consistent reporting timelines~~
- ~~Provide clarity around who will receive the information and how it will be used~~

~~During the development of concepts, the DSR SDT considered the FERC directive to "further define sabotage". There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to reporting events. The term "sabotage" is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events~~

~~as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.~~

~~The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.~~

~~The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.~~

~~**Data Gathering**~~

~~The requirements of EOP-004-1 require that entities "promptly analyze Bulk Electric System disturbances on its system or facilities" (Requirement R2). The requirements of EOP-004-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.~~

Law Enforcement Reporting

The reliability objective of EOP-004-~~3~~ 4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC

- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

~~**Present expectations of the industry under CIP-001-1a:**~~

~~It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have led to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.~~

~~**Coordination of Local and State Law Enforcement Agencies with the FBI**~~

~~The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.~~

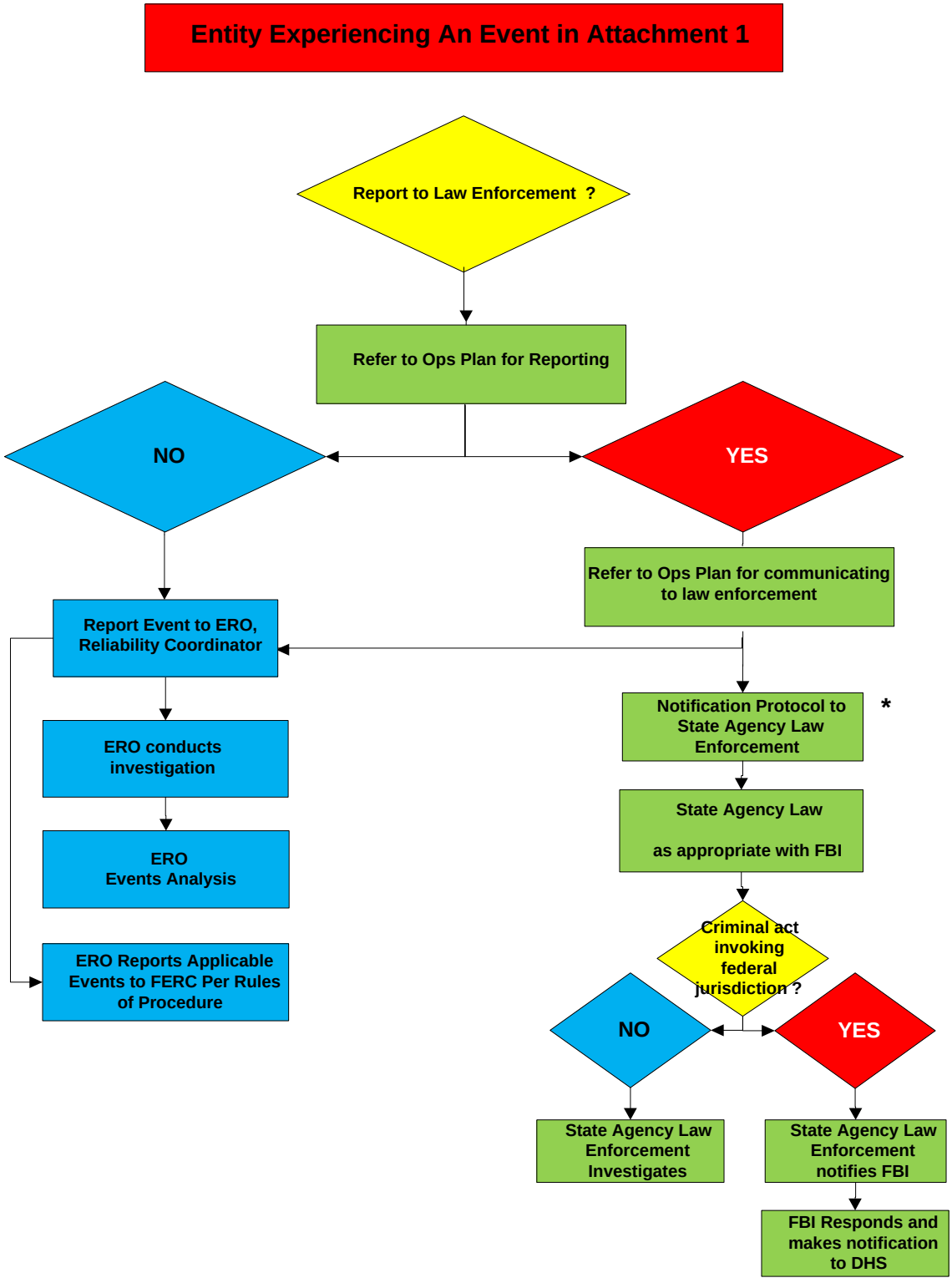
~~**Coordination of Local and Provincial Law Enforcement Agencies with the RCMP**~~

~~A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).~~

~~**A Reporting Process Solution – EOP-004**~~

~~A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.~~

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

CIP-001 — Sabotage Reporting

EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

Summary of Concepts and Assumptions:

The Standard:

- Requires reporting of "events" that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

Discussion of Disturbance Reporting

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.
3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and

~~developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).~~

~~*Discussion of Event Reporting*~~

~~There are situations worthy of reporting because they have the potential to impact reliability.~~

~~Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.~~

~~Examples of such events include:~~

~~Bolts removed from transmission line structures~~

~~Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)~~

~~Destruction of Bulk Electric System equipment~~

~~**What about sabotage?**~~

~~One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *". . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."*~~

~~Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.~~

~~Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.~~

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information as known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination

of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

~~Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.~~

~~**Collection of Reportable Information or "One stop shopping"**~~

~~The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.~~

~~The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.~~

~~ill assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.~~

Rationale

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

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Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standard EOP-004-4

Applicable Standard(s)

- EOP-004-4 — Event Reporting

Requested Retirement(s)

- EOP-004-3 — Event Reporting

Prerequisite Standard(s)

None.

Applicable Entities

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

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standard making the standard more Results-based.

Effective Date

EOP-004-4 — Event Reporting

Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition
None.

Retirement Date

EOP-004-3 — Event Reporting
Reliability Standard EOP-004-3 shall be retired immediately prior to the effective date of EOP-004-4 in the particular jurisdiction in which the revised standard is becoming effective.

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-004-4 – Event Reporting**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time frame to have an event reporting Operating Plan. The assignment of the Lower VRF was made based on the premise that failure to have an event reporting Operating Plan would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-004-4, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an event reporting Operating Plan that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to have an event reporting Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-004-4, R1			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

VRF Justifications for EOP-008-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event operating plan Operating Plan and mirrors the Requirements of EOP-004-3 with some minor edits. The VSL's for R1 were not revised. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-004-4, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Assessment time frame that requires entities to report events per their Operating Plan. If violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. .
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the entity to report events per their Operating Plan. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned, so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 uses similar language from EOP-004-3, Requirement R2, and the VRF remains unchanged from earlier versions.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to report events per the Operating Plan would not be expected to have an adverse impact on the bulk power system, or the ability to effectively monitor and control the bulk electric system.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-004-4, R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after recognition of meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.

VSL Justifications for EOP-004-4, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-004-4 deal with having an event reporting Operating Plan and reporting events, and Requirement 2 language of EOP-004-4 is only slightly changed from EOP-004-3. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-004-4, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

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Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-004-4		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-004-03, Requirement R3 **R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*	Recommended for retirement.	The EOP SDT recommends retirement of Requirement R3 under Criterion B1, administrative; the R3 requirement in EOP-004-3 requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Contact lists are administrative in nature.

Standard Development Timeline

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

Description of Current Draft

EOP-005-3 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	07/15/2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	06/22/2016 – 08/08/2016
45-day formal comment period with additional ballot	08/30/2016 – 10/14/2016
10-day final ballot	11/01/2016 – 11/11/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

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

A. Introduction

1. **Title:** System Restoration from Blackstart Resources

2. **Number:** EOP-005-~~2~~3

3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ~~assure~~ ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Operators

   4.1.2. Generator Operators

   4.1.3. Transmission Owners identified in the Transmission Operators restoration plan

   4.1.4. Distribution Providers identified in the Transmission Operators restoration plan

5. **Effective Date:** See the Implementation Plan for EOP-005-3.~~Twenty four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.~~

6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Transmission Operator shall ~~have~~ develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the ~~shut down~~shutdown area to service.~~, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System.~~ The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

1.1. Strategies for system restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.

1.2. A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.

1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

1.6. Identification of acceptable operating voltage and frequency limits during restoration.

1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

1.9. Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M2. Each Transmission Operator shall have evidence such as ~~e-mails with~~dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan in accordance with Requirement R2.

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator ~~annually~~ at least once each 15 calendar months on a mutually-

agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~**3.1.** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary. (Retirement approved by FERC effective January 21, 2014.)~~

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, ~~e-mails with~~dated electronic receipts, or registered mail receipts, that it has ~~annually~~ at least once each 15 calendar months reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement ~~R3~~R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes is confusing. Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan.

Therefore, the EOP SDT revisions now provide clarity. By revising this to read as "to reflect System modifications that would change the ability to implement its restoration plan," the intent was that the TOP update its restoration plan when major modifications need to be made that affect its ability to implement its restoration plan as describe in Requirement R1 Parts, not that the Transmission Operator has to make updates for minor revisions, such as element number changes or device changes that have no significance to the implementation of the plan.

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan ~~within 90 calendar days after identifying any unplanned permanent~~to reflect System modifications~~,~~ that would change the ability ~~or prior~~ to ~~implementing~~ implement ~~a planned BES modification, that would change the implementation of~~ its restoration plan, as follows:~~.~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. ~~Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same~~ No more than 90

calendar day perioddays after the Transmission Operator identifies any unplanned System modifications; and.

4.1.4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, e-mails withhistories, dated electronic receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, available in its primary and backup control rooms and available to its System Operators prior to its implementation effective date in accordance with Requirement R5.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response for each step of the restoration. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

R6. Each Transmission Operator 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 at least once every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

M6. Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

R7. Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each

~~affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~

~~**M7.** If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it implemented its restoration plan or restoration plan strategies in accordance with Requirement R7.~~

~~**R8.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~

~~**M8.**~~**M7.** ~~If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved in such an event shall have evidence, such as voice recordings, e-mail, dated computer printouts, or operator logs, that it resynchronized shut down areas in accordance with Requirement R8.~~

R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

7.2. A list of required tests including:

7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. The minimum duration of each of the required tests.

M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement ~~R9~~R7.

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 would allow operating personnel to gain experience and coordination needed through all of the stages of restoration, including coordination needed in the transfer of control back to the Balancing Authority.

R8. Each Transmission Operator shall include within its operations training program, ~~annual~~ System restoration training at least once each 15 calendar months for its System Operators ~~to assure the proper execution of its restoration plan~~. ~~-~~This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

8.1. System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan

8.2. Restoration priorities

8.3. Building of cranking paths

8.4. Synchronizing (re-energized sections of the System)

~~8.4.~~8.5. Transition to Balancing Authority for Area Control Error and Automatic Generation Control

~~M9.~~M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement ~~R10~~R8.

R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M10.~~M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement ~~R11~~R9.

R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M11.~~M10. Each Transmission Operator shall have evidence~~, such as training records,~~ that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement ~~R12~~R10.

R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M12.~~M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement ~~R13~~R11.

R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M13.~~M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement ~~R14~~R12.

R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M14.~~M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as e-mails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within ~~twenty-four~~24 hours of such changes in accordance with Requirement ~~R15~~R13.

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement ~~R9~~R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

~~M15.~~M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement ~~R16~~R14.

R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

15.1. System restoration plan including coordination with the Transmission Operator.

15.2. The procedures documented in Requirement ~~R14~~R12.

~~M16.~~M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement ~~R17~~R15.

R16. Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~M17.~~M16. Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement ~~R18~~R16.

C. Compliance

1. Compliance Monitoring Process

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

Compliance Monitoring Period and Reset Time Frame: ~~Not applicable~~
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to

provide other evidence to show that it was compliant for the full-time period since the last audit.

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

The Transmission Operator 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:

- Approved restoration plan and any restoration plans in force since the last ~~compliance audit~~monitoring activity for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator's ~~annually~~ reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of an updated restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- The current restoration plan approved by the Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
- ~~Implementation of its restoration plan or restoration plan strategies on any occasion for three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R7, Measure M7.~~
- ~~Resynchronization of shut down areas on any occasion over three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R8, Measure M8.~~
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement ~~R9~~R7, Measure ~~M9~~M7.
- ~~Actual training~~ Training program materials or descriptions for three calendar years for Requirement ~~R10~~R8, Measure ~~M10~~M8.

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last ~~compliance audit~~monitoring activity, as well as one previous ~~compliance audit~~monitoring activity period for Requirement ~~R12~~R10, Measure ~~M12~~M10.

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator, applicable Transmission Owner, and applicable Distribution ~~provider~~ Provider 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:

- ~~Actual training~~ Training program materials or descriptions and ~~actual~~ training records for three calendar years for Requirement ~~R11~~R9, Measure ~~M11~~M9.

If a Transmission Operator, applicable Transmission ~~owner~~Owner, or applicable Distribution Provider is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Transmission Operator and Generator Operator with a Blackstart Resource 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:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in force since its last ~~compliance audit~~monitoring activity for Requirement ~~R13~~R11, Measure ~~M13~~M11.

The Generator Operator with a Blackstart Resource 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:

- Current documentation and any documentation in force since its last ~~compliance audit~~monitoring activity on procedures to start each Blackstart Resource and for energizing a bus for Requirement ~~R14~~R12, Measure ~~M14~~M12.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement ~~R15~~R13, Measure ~~M15~~M13.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement ~~R16~~R14, Measure ~~M16~~M14.

- ~~Actual training~~ Training program materials and ~~actual~~ training records for three calendar years for Requirement ~~R17~~R15, Measure ~~M17~~M15.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

The Generator Operator 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:

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last ~~compliance audit~~monitoring activity for Requirement ~~R18~~R16, Measure ~~M18~~M16.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant.

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

1.1. Compliance Monitoring and Enforcement Processes

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

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

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator has an approved plan but failed to comply with one of the ~~sub-~~requirement~~s~~ parts within ~~the requirement~~Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the ~~sub-~~requirement~~s~~ parts within ~~the requirement~~Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three of the ~~sub-r~~equirement~~s~~ parts within ~~the requirement~~Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement it.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. ~~OR~~ ~~The Transmission Operator provided the information to all entities but was up to 10 calendar days late in doing so.~~	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. ~~OR~~ ~~The Transmission Operator provided the information to all entities but was more than 10 and less than or~~	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~ effective date of the plan. ~~OR~~ ~~The Transmission Operator provided the information to all entities but was more than 20 and less than or~~	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its approved restoration plan with a

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		~~equal to 20 calendar days late in doing so.~~	~~equal to 30 calendar days late in doing so.~~	description of any changes to their roles and specific tasks prior to the effective date.~~The Transmission Operator provided the information to all entities but was more than 30 calendar days late in doing so.~~
R3.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change within 30 calendar days after the mutually-agreed, pre-determined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 30 and less than or equal to 60 calendar days after the mutually-agreed, pre-determined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 60 and less than or equal to 90 calendar days after the mutually-agreed, pre-determined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 90 calendar days after the mutually-agreed, pre-determined schedule.
R4.	The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator within 90 calendar days of an unplanned change. OR	The Transmission Operator ~~failed to~~ updated and ~~submit~~ submitted its restoration plan to the Reliability Coordinator ~~within more than 90~~ between 91 calendar days ~~but less than~~ and 120	The Transmission Operator ~~has failed to~~ updated and ~~submit~~ submitted its restoration plan to the Reliability Coordinator ~~within more than 120~~ between 121 calendar days ~~but less than~~ 150 calendar	The Transmission Operator has failed to update and submit its restoration plan to the Reliability Coordinator within ~~more than~~ 150 calendar days of an unplanned change. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 30 calendar days prior to a planned change.	calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 20 calendar days prior to a planned change.	days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 10 calendar days prior to a planned change.	The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator prior to a planned BES modification.
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its ~~implementation~~ effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the ~~sub-~~	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the ~~sub-~~	The Transmission Operator performed the verification but did not complete it within the ~~five calendar~~	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~requirements~~requirement parts.	~~requirements~~requirement parts.	~~year period~~required time frame.	OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the ~~sub-requirements~~requirement parts.
~~**R7.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not implement its restoration plan following a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES. Or, if the restoration plan cannot be executed as expected, the Transmission Operator did not utilize its restoration plan strategies to facilitate restoration.~~
~~**R8.**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator resynchronized without approval of the Reliability Coordinator or not in accordance with the~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~established procedures of the Reliability Coordinator following a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service.~~
~~R9~~R7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the ~~sub-requirements~~requirement parts of Requirement ~~R9~~R7.
~~R10~~R8.	The Transmission Operator's training does not address one of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator's training does not address two of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator's training does not address three or more of the ~~sub-requirements~~requirement parts of Requirement ~~R10~~R8.	The Transmission Operator has not included System restoration training in its operations training program.
~~R11~~R9.	The Transmission Operator, applicable Transmission	The Transmission Operator, applicable Transmission	The Transmission Operator, applicable Transmission	The Transmission Operator, applicable Transmission

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement ~~R11~~ R9 within a two-~~-~~calendar-~~-~~year period.	Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement ~~R11~~ R9 within a two-calendar-~~-~~year period.	Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement ~~R11~~ R9 within a two-calendar-~~-~~year period.	Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement ~~R11~~ R9 within a two-~~-~~calendar-~~-~~year period.
~~R12~~R10.	N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for ~~their~~ its participation from the Reliability Coordinator.
~~R13~~R11.	N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
~~R14~~R12.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				procedures for each Blackstart Resource.
~~R15~~R13.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.
~~R16~~R14.	The ~~GOP~~ Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in ~~R16.1~~Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60	The ~~GOP~~ Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 ~~days~~ to 90 calendar days after the request.	The ~~GOP~~ Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calendar days ~~of~~ after the request.			
~~R17~~R15.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement ~~R17~~ R15 within a two-~~-~~calendar-~~-~~year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement ~~R17~~ R15 within a two-calendar-~~-~~year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement ~~R17~~ R15 within a two-calendar-~~-~~year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement ~~R17~~ R15 within a two-~~-~~calendar-~~-~~year period.
~~R18~~R16.	N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	May 2, 2007	Approved by the Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements. Updated Measures and Compliance to match new requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the standard drafting team's (SDT's) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in EOP-005-3 – System Restoration from Blackstart Resources. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard

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

Guideline (3) – Consistency among Reliability Standards

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

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

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

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
NERC VRF Discussion	R1 is a requirement in an Operations Planning and a Real-time Operations time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires Transmission Operator to develop, maintain and implement a restoration plan that is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for development, maintenance and implementation of a restoration plan. This is similar to EOP-005-2, Requirement R1 which also places similar requirements of the Reliability Coordinator and is assigned a High VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to develop and implement a restoration plan could directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement could lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "High" which is consistent with NERC guidelines for similar requirements.

VRF Justifications for EOP-005-3, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to develop, maintain and implement a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator has an approved plan, but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan, but failed to comply with three of the ~~r~~equirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement it.

VSL Justifications for EOP-005-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirement" with "requirement part" and adding a Severe VSL regarding the failure to implement the restoration plan. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Transmission Operator to distribute to entities identified in its approved restoration plan with description of any changes to their roles and specific tasks and is administrative in nature. A violation of this requirement has been assigned a Medium VRF, consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for description of changes distribution of a restoration plan. This is a slight revision replacing “implementation date” to “effective date” requirement (EOP-005-2, Requirement R2) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to distribute changes of a restoration plan 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective, which is to distribute changes of a restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R2			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.

VSL Justifications for EOP-005-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "implementation" with "effective" and adding a Severe VSL regarding the failure to provide at least half of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R2 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Transmission Operator to review its restoration plan within 15 calendar months of the last review. A violation of this requirement has been assigned a Medium VRF because, 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 This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has does not contain parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for review of a restoration plan. This is a revised requirement (EOP-005-2, Requirement R3) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to review a restoration plan 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective, which is to review the restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R3			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator submitted the reviewed restoration plan or confirmation of no change within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 90 calendar days after the mutually-agreed, predetermined schedule.

VSL Justifications for EOP-005-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and assigned at the Severe level. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Transmission Operator to update its restoration plan to reflect System modifications and submit it to its Reliability Coordinator for approval. A violation of this requirement has been assigned a Medium VRF because, 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 This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts regarding unplanned and planned System modifications timelines and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for an update of its restoration plan and submission for Reliability Coordinator approval to reflect System modifications. This is a revised requirement (EOP-005-2, Requirement R4) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update a restoration plan 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R4	
Proposed VRF	**Medium**
	R4 contains only one objective, which is to update its restoration plan and submit for Reliability Coordinator approval to reflect System modifications. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator within 90 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 30 calendar days prior to a planned change.	The Transmission Operator updated and submitted its restoration plan to the Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 20 calendar days prior to a planned change.	The Transmission Operator updated and submitted its restoration plan to the Reliability Coordinator between 121 calendar days 150 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator at least 10 calendar days prior to a planned change.	The Transmission Operator has failed to update and submit its restoration plan to the Reliability Coordinator within 150 calendar days of an unplanned change. OR The Transmission Operator failed to update and submit its restoration plan to the Reliability Coordinator prior to a planned BES modification.

VSL Justifications for EOP-005-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the Transmission Operator to have a copy of its latest Reliability Coordinator approved restoration plan in its primary and backup control rooms. A violation of this requirement has been assigned a Lower VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains a single part regarding coordination and compatibility of the plans and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for having its Reliability Coordinator approved restoration plan within its primary and backup control rooms. This is a simply revised requirement (EOP-005-2, Requirement R5) that is assigned a Lower VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a restoration plan within primary and backup control rooms 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective, which is to have a restoration plan within primary and backup control rooms. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.

VSL Justifications for EOP-005-3, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "implementation" with "effective." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R5 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in a Long-term Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the Transmission Operator to verify that its restoration plan accomplishes its intended function. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains three parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for verification that its restoration plan accomplishes its intended function. This is a slightly revised requirement (EOP-005-2, Requirement R6) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to verify that its restoration plan accomplishes its intended function 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective, which is to verify that its restoration plan accomplishes its intended function. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R6			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.

VSL Justifications for EOP-005-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirements" with "requirement parts." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Transmission Operator to have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding Blackstart Resource testing topics and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for the Transmission Operator to have Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R9) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include Blackstart Resource testing requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R7	
Proposed VRF	**Medium**
	R7 contains only one objective which is to include within its restoration plan requirements to verify each Blackstart Resource is capable of meeting the requirements of its restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address one or more of the requirement parts of Requirement R7.

VSL Justifications for EOP-005-3, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with restoration plans similar to EOP-005-2. The VSLs were revised slightly by replacing "subrequirements" with "requirement parts." The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the Transmission Operator to include within its operations training program System restoration training. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains several parts regarding System restoration training. Only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to be included within its operations training program. This is a revised requirement (EOP-005-2, Requirement R10) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to include within its operations training program System restoration training 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective, which is to include within its operations training program System restoration training. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R8			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.

VSL Justifications for EOP-005-3, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing “subrequirement” with “requirement parts.” The VSLs for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
NERC VRF Discussion	R9 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 requires the Transmission Operator, applicable Transmission Owners, and applicable Distribution Providers to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for System restoration training to field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. This is a revised requirement (EOP-005-2, Requirement R11) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks 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.

VRF Justifications for EOP-005-3, R9	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective, which is to provide a minimum of two hours of System restoration training to their field switching personnel identified as performing unique tasks associated with the transmission Operator's restoration plan that are outside of their normal tasks. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R9			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year period.

VSL Justifications for EOP-005-3, R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R9	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R10	
Proposed VRF	**Medium**
NERC VRF Discussion	R10 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires the Transmission Operator to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R12) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective, which is to participate in restoration drills. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from the Reliability Coordinator.

VSL Justifications for EOP-005-3, R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs were revised slightly by replacing “their” with “its.” The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose 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.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
NERC VRF Discussion	R11 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 requires each Transmission Operator and each Generator Operator with a Blackstart Resource to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for Blackstart Resource Agreements. This is an unrevised requirement (EOP-005-2, Requirement R13) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols that specify the terms and conditions of their agreement 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R11	
Proposed VRF	**Medium**
	R11 contains only one objective, which is to have written Blackstart Resource Agreements. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R11			
Lower	**Moderate**	**High**	**Severe**
N/A	The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.	N/A	The Transmission Operator and Generator Operator with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.

VSL Justifications for EOP-005-3, R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R11	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R12	
Proposed VRF	**Medium**
NERC VRF Discussion	R12 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 requires each Generator Operator with a Blackstart Resource to have documented procedures for starting each Blackstart Resource and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for documented procedures for starting each Blackstart Resource and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R14) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have documented procedures for starting each Blackstart Resource and energizing a bus 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective, which is to have to have documented procedures for starting each Blackstart Resource and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R12			
Lower	Moderate	High	Severe
N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.

VSL Justifications for EOP-005-3, R12	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R12 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R12	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
NERC VRF Discussion	R13 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R13 requires each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. This is an unrevised requirement (EOP-005-2, Requirement R15) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan 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.

VRF Justifications for EOP-005-3, R13	
Proposed VRF	**Medium**
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R13 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R13			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

VSL Justifications for EOP-005-3, R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R13 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R13	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
NERC VRF Discussion	R14 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R14 requires each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. This is an unrevised requirement (EOP-005-2, Requirement R16) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R14	
Proposed VRF	**Medium**
	R14 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to perform Blackstart Resource tests in accordance with the testing requirements set by the Transmission Operator. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R14			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.

VSL Justifications for EOP-005-3, R14	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R14 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R14	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
NERC VRF Discussion	R15 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R15 requires each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains two parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. This is an unrevised requirement (EOP-005-2, Requirement R17) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R15	
Proposed VRF	**Medium**
	R15 contains only one objective, which is to have to have each Generator Operator with a Blackstart Resource to provide training to its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R15			
Lower	**Moderate**	**High**	**Severe**
The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year period.

VSL Justifications for EOP-005-3, R15	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R15 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R15	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
NERC VRF Discussion	R16 is a requirement in an Operations Planning time frame 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R16 requires each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. A violation of this requirement has been assigned a Medium VRF because, 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. This is consistent with FERC guideline G1 regarding Emergency Operations.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement contains one part and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations. This is an unrevised requirement (EOP-005-2, Requirement R18) that is assigned a Medium VRF.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have each Generator Operator to participate in the Reliability Coordinator's restoration drills, exercises, or simulations 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.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for EOP-005-3, R16	
Proposed VRF	**Medium**
	R16 contains only one objective, which is to have to have each Generator Operator participate in the Reliability Coordinator's restoration drills, exercises, or simulations. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-005-3, R16			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Operator failed to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.

VSL Justifications for EOP-005-3, R16	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	EOP-005-3 deals with System restoration from Blackstart Resources similar to EOP-005-2. The VSLs for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R16 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-005-3, R16	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standard Audit Worksheet[1]

EOP-005-3 – System Restoration from Blackstart Resources

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	Audit
Names of Auditors:	Supplied by CEA

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Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	RC	RP	RSG	TO	TOP	TP	TSP
R1												X		
R2												X		
R3												X		
R4												X		
R5												X		
R6												X		
R7												X		
R8												X		
R9		X[3]									X[3]	X[3]		
R10												X		
R11				X[4]								X		
R12				X[4]										
R13				X[4]										
R14				X[4]										
R15				X[4]										

[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. 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.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

[3] That is identified in the Transmission Operators restoration plan.

R16				X										

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Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			
R7			
R8			
R9			
R10			
R11			
R12			
R13			
R14			
R15			
R16			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

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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)

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R1 Supporting Evidence and Documentation

R1. Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. The restoration plan shall include:

1.1. Strategies for system restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.

1.2. A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.

1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.

1.6. Identification of acceptable operating voltage and frequency limits during restoration.

1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.

1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

1.9. Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

M1. Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

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Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
The entity's most recent restoration plan with revision history
Documented approval from its Reliability Coordinator
Times that Disturbances have occurred and evidence that the restoration plan was implemented

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R1

This section to be completed by the Compliance Enforcement Authority

	Verify that the restoration plan was implemented (such as during Disturbances)
	Verify each Transmission Operator has a dated, documented System restoration plan developed in accordance with R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator.
	Verify the restoration plan includes:
	(Part 1.1) Strategies for system restoration that are coordinated with the Reliability Coordinator's high level strategy for restoring the Interconnection.
	(Part 1.2) A description of how all Agreements or mutually agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.
	(Part 1.3) Procedures for restoring interconnections with other Transmission Operators under the direction of the Reliability Coordinator.
	(Part 1.4) Identification of each Blackstart Resource and its characteristics including but not limited to the following:
	(Part 1.4) The name of each Blackstart Resource,
	(Part 1.4) Location of each Blackstart Resource,

	(Part 1.4) Megawatt and megavar capacity of each Blackstart Resource, and
	(Part 1.4) Type of each Blackstart Resource.
	(Part 1.5) Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.
	(Part 1.6) Identification of acceptable operating voltage and frequency limits during restoration.
	(Part 1.7) Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.
	(Part 1.8) Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.
	(Part 1.9) Operating Processes for transferring authority back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.
Note to Auditor:	

Auditor Notes:

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R2 Supporting Evidence and Documentation

R2. Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.

M2. Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.

Registered Entity Response (Required):
Question: Have there been any changes to the approved restoration plan that resulted in changes to the identified entities' roles and specific tasks? ☐ Yes ☐ No
Provide an explanation in the Compliance Narrative section.

Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
The entity's most recent restoration plan with revision history
Dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R2
This section to be completed by the Compliance Enforcement Authority

	Has responded to the applicability question above and provided evidence of compliance if the response was 'yes.'
	Had changes to the approved restoration plan.
	Has notified entities identified in its approved restoration plan of any changes to their roles and specific tasks.
	Has made notification of any changes of roles and specific tasks prior to the effective date of the restoration plan.
Note to Auditor: Evidence may include, but is not limited to, dated electronic receipts or registered mail receipts.	

Auditor Notes:

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R3 Supporting Evidence and Documentation

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator at least once each 15 calendar months on a mutually-agreed, predetermined schedule.

M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts, that it has at least once each 15 calendar months reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
The mutually-agreed, predetermined schedule for submitting the entity's restoration plan to its Reliability Coordinator.
Evidence of entity's review of its restoration plan
Evidence of submission of the entity's reviewed restoration plan to its Reliability Coordinator

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R3

This section to be completed by the Compliance Enforcement Authority

	Verify the restoration plan was reviewed at least once each 15 calendar months.
	Verify the restoration plan was submitted to its Reliability Coordinator on a mutually agreed,

	predetermined schedule.
Note to Auditor: Evidence may include, but is not limited to, a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts.	

Auditor Notes:

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R4 Supporting Evidence and Documentation

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows:

4.1 No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications; and

4.2 No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.

Registered Entity Response (Required):
Question: Were there any planned or unplanned System modifications that would change the ability to implement its restoration plan? ☐ Yes ☐ No
Provide an explanation in the Compliance Narrative section.

Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence that the restoration plan was updated and submitted to its Reliability Coordinator within 90 calendar days after identifying unplanned changes.
Evidence the restoration plan was updated and submitted to its Reliability Coordinator no less than 30 calendar days prior to the implementation of planned System modifications.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R4

This section to be completed by the Compliance Enforcement Authority

	Has responded to the applicability question and provided evidence of compliance if the response was 'yes.'
	Verify the entity updated and submitted its restoration plan within 90 calendar days after identifying any unplanned System modifications that would change the ability to implement its restoration plan.
	Verify the entity updated and submitted its restoration plan no less than 30 days prior to the implementation of planned System modifications that would change the ability to implement its restoration plan.
Note to Auditor:	

Auditor Notes:

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R5 Supporting Evidence and Documentation

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date.

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Latest Reliability Coordinator approved restoration plan
Location of the entity's primary and backup control rooms

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R5

This section to be completed by the Compliance Enforcement Authority

	Verify the entity has a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms.
	Verify the copy was made available prior to its effective date.
Note to Auditor:	

Auditor Notes:

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R6 Supporting Evidence and Documentation

R6. Each Transmission Operator 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 at least once every five years. Such analysis, simulations or testing shall verify:

6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

M6. Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence showing verification of the entity's restoration plan
Entity's restoration plan

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R6

This section to be completed by the Compliance Enforcement Authority

	Determine if the entity verified through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function to:
	(R6.1) Verify the capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.
	(R6.2) Verify the location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.
	(R6.3) Verify the capability of generating resources required to control voltages and frequency within acceptable operating limits.
	Verify the entity completed this analysis at least once every five years.

Note to Auditor: Verify the entity has documentation such as, but not limited to, power flow outputs, demonstrating it has verified that its latest restoration plan will accomplish its intended function. Auditors should verify that the timeframe for completion of the analysis or testing contemplated in R6 does not exceed five years from the date of the last analysis or testing performed by the entity.

Part 1.6 of the standard requires the restoration plan to include identification of acceptable operating voltage and frequency limits during restoration.

Auditor Notes:

DRAFT

R7 Supporting Evidence and Documentation

R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include:

7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

7.2. A list of required tests including:

7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. The minimum duration of each of the required tests.

M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
The entity's Blackstart Resource testing requirements

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R7

This section to be completed by the Compliance Enforcement Authority

	The entity has Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of the restoration plan. Testing requirements shall include:
	(Part 7.1) The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.
	(Part 7.2.1) The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.
	(Part 7.2.2) The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits. See Note to Auditor below.
	(Part 7.3) The minimum duration of each of the required tests.
Note to Auditor:	

Auditor Notes:

DRAFT

R8 Supporting Evidence and Documentation

R8. Each Transmission Operator shall include within its operations training program, System restoration training at least once each 15 calendar months for its System Operators. This training program shall include training on the following:

8.1. System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan.

8.2. Restoration priorities.

8.3. Building of cranking paths.

8.4. Synchronizing (re-energized sections of the System).

8.5. Transition to Balancing Authority for Area Control Error and Automatic Generation Control.

M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Electronic or hard copy of the training program material provided for its System Operators for System restoration training
The entity's operations training program.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R8

This section to be completed by the Compliance Enforcement Authority

	The entity has a training program that is provided to its System Operators for System restoration training.
	The training program includes system restoration training at least once each 15 calendar months for its System Operators.
	The training program includes:
	(Part 8.1) System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan.
	(Part 8.2) Restoration priorities.
	(Part 8.3) Building of cranking paths.
	(Part 8.4) Synchronizing (the re-energized sections of the System).
	(Part 8.5) Transition to Balancing Authority for Area Control Error and Automatic Generation Control.
Note to Auditor: Actual performance of the training is covered under PER-005.	

Auditor Notes:

DRAFT

R9 Supporting Evidence and Documentation

R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks.

M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Electronic or hard copy of the training program material provided to the entity's field switching personnel for System restoration training
Corresponding training records including training dates and duration

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R9

This section to be completed by the Compliance Enforcement Authority

	The entity identified field switching personnel performing unique tasks associated with the restoration plan that are outside of their normal tasks.

	Field switching personnel performing unique tasks, that are outside of their normal tasks, associated with the restoration plan receive a minimum of two hours of System restoration training every two calendar years.
Note to Auditor: Evidence may include, but is not limited to, a copy of training records/materials with training dates, topic, attendees and duration.	

Auditor Notes:

DRAFT

R10 Supporting Evidence and Documentation

R10. Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator.

M10. Each Transmission Operator shall have evidence that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.

Registered Entity Response (Required):

Question: Has the entity been requested by the Reliability Coordinator to participate in its restoration drills, exercises, or simulations? ☐ Yes ☐ No

Provide an explanation in the Compliance Narrative section.

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
If applicable, evidence of participation in restoration drills, exercises, or simulations

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R10

This section to be completed by the Compliance Enforcement Authority

	Verify the entity has responded to the applicability question and provided evidence of compliance if the response was yes.
	Validate that the entity, as requested, participated in the Reliability Coordinator's restoration drills, exercises, or simulations. See Note to Auditor below.
Note to Auditor: An example of evidence may include, but is not limited to, logs. Note that EOP-006-3	

requires Reliability Coordinators to request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

Auditor Notes:

DRAFT

R11 Supporting Evidence and Documentation

R11. Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements.

M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R11

This section to be completed by the Compliance Enforcement Authority

	Verify that the entities with a Blackstart Resource have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols specifying the terms and conditions of their arrangement.
	Verify agreements include references to the Blackstart Resource testing requirements.
Note to Auditor:	

Auditor Notes:

DRAFT

R12 Supporting Evidence and Documentation

R12. Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus.

M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Procedures for starting each Blackstart Resource and energizing a bus

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R12

This section to be completed by the Compliance Enforcement Authority

	Verify the entity with a Blackstart Resource has documented procedures for starting each Blackstart Resource and energizing a bus.
Note to Auditor:	

Auditor Notes:

DRAFT

R13 Supporting Evidence and Documentation

R13. Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change.

M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as e-mails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.

Registered Entity Response (Required):

Question: Has the entity with a Blackstart Resource had any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan?

☐ **Yes** ☐ **No**

Provide an explanation in the Compliance Narrative section.

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan
E-mails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R13

This section to be completed by the Compliance Enforcement Authority

	The entity responded to the applicability Question and provided evidence of compliance if the response was 'yes.'
	The entity with a Blackstart Resource notified its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change.
Note to Auditor:	

Auditor Notes:

DRAFT

R14 Supporting Evidence and Documentation

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan.

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated documentation of the entity's Blackstart Resource test results
Evidence, such as e-mails with receipts or registered mail receipts, that the entity provided these records to its Reliability Coordinator and Transmission Operator when requested

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R14

This section to be completed by the Compliance Enforcement Authority

	The entity maintains Blackstart Resource test records.
	The entity Blackstart Resource testing is in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan.
	(Part 14.1) Test records shall include at a minimum:
	(Part 14.1) Name of the Blackstart Resource unit tested.
	(Part 14.1) Date of the test.
	(Part 14.1) Duration of the test.
	(Part 14.1) Time required to start the unit.
	(Part 14.1) Any testing requirements not met under R7.
	(Part 14.2) The entity has documentation such as e-mails with receipts, or registered mail receipts, that it provided the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.
Note to Auditor:	

Auditor Notes:

DRAFT

R15 Supporting Evidence and Documentation

R15. Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following:

15.1. System restoration plan including coordination with the Transmission Operator

15.2. The procedures documented in Requirement R12.

M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and synchronization of its Blackstart Resource generation units
Dated training records including training dates and durations showing that it has provided training

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R15

This section to be completed by the Compliance Enforcement Authority

	Verify the entity with a Blackstart Resource has provided a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus.
	Verify the training program includes:
	(Part 15.1) System Restoration plan including coordination with the Transmission Operator.
	(Part 15.2) The procedures documented in R12 for starting a blackstart resource and energizing a bus.
Note to Auditor:	

Auditor Notes:

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R16 Supporting Evidence and Documentation

R16. Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.

M16. Each Generator Operator shall have evidence, such as dated training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.

Registered Entity Response (Required):

Question: Has the entity been requested by the Reliability Coordinator to participate in its restoration drills, exercises, or simulations? ☐ Yes ☐ No

Provide an explanation in the Compliance Narrative section.

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
If applicable, evidence of participation in restoration drills, exercises, or simulations

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-005-3, R16

This section to be completed by the Compliance Enforcement Authority

	Verify the entity responded to the applicability question and provided evidence of compliance if the response was yes.
	Verify the entity has evidence such as, but not limited to, dated training records that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so.

Note to Auditor: This requirement is applicable to all Generator Operators, regardless of whether they have a Blackstart Resource.

Auditor Notes:

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Additional Information:

Reliability Standard

The full text of EOP-005-3 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

Still needed. Order No. 749, 134 FERC ¶ 61,215 (2011)

Selected Glossary Terms

The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Demand: 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: 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.

Net Energy for Load: 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.

Total Internal Demand: The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	7/8/16	NERC Compliance Assurance, RSAW Task Force	New Document

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

DRAFT

Standard Development Timeline

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

Description of Current Draft

EOP-006-3 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/15 – 08/19/15

Anticipated Actions	Date
45-day formal comment period with ballot	06/22/2016 – 08/08/2016
45-day formal comment period with additional ballot	08/30/2016 – 10/14/2016
10-day final ballot	11/01/2016 - 11/11/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

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

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-~~2~~3
3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinators
5. **Proposed Effective Date:** ~~Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.~~ See the Implementation Plan for EOP-006-3.
6. Standard-Only Definition: None.

B. Requirements and Measures

R1. Each Reliability Coordinator shall ~~have~~ develop, maintain, and implement a Reliability Coordinator Area restoration plan. ~~-~~The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. ~~-~~The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. ~~-~~The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

- **1.1.** A description of the high~~-~~level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.
- ~~**1.2.** Operating Processes for restoring the Interconnection.~~
- ~~**1.3.** Descriptions of the elements of coordination between individual Transmission Operator restoration plans.~~
- ~~**1.4.** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators.~~

~~1.5.~~1.2. Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with adjacent Transmission Operators in other Reliability Coordinator Areas, and with ~~other~~ adjacent Reliability Coordinators.

~~1.6.~~1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

~~1.7.~~1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

~~1.8.~~1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

~~1.9.~~1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan ~~in accordance with Requirement R1~~and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as ~~e-mails with~~electronic receipts, posting to a secure web-site with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

R3. Each Reliability Coordinator shall review its restoration plan within ~~13~~ 15 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within ~~13~~ 15 calendar months of the last review in accordance with Requirement R3.

R4. Each Reliability Coordinator shall review ~~their~~ its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. If ~~the~~ a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved ~~in~~ within 30 calendar days of written notification.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4.

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. ~~-~~The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence~~,~~ such as a dated review signature sheet or ~~emails~~electronic receipt~~,~~ that it has reviewed, approved or disapproved, and notified its Transmission Operator~~'~~s within 30 calendar days following the receipt of the restoration plan from the Transmission Operator ~~-~~in accordance with Requirement R5.

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the ~~implementation~~ effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator shall have documentation such as ~~e-mail~~electronic receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the ~~implementation~~ effective date in accordance with Requirement R6.

~~**R7.** Each Reliability Coordinator shall work with its affected Generator Operators, and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~

~~M7. Each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it monitored and coordinated restoration progress in accordance with Requirement R7.~~

~~R8. The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*~~

~~M8.~~M7. ~~If there has been a resynchronizing of an islanded area, each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, or operator logs, that it coordinated or authorized resynchronizing in accordance with Requirement R8.~~

~~R9.~~R7. Each Reliability Coordinator shall include within its operations training program, at least once each 15 calendar months,~~annual~~ System restoration training for its System Operators ~~to assure the proper execution of its restoration plan~~. ~~-~~This training program shall address the following: ~~–~~*[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~9.1.~~7.1. The coordination role of the Reliability Coordinator

~~9.2.~~7.2. Re-establishing the Interconnection

M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement ~~R9~~R7.

~~R10.~~R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~10.1.~~8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

M8. Each Reliability Coordinator shall have evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable ~~and that~~ Transmission Operator~~s~~ and Generator Operator~~s~~ to participate per Requirement R8 and R8 Part 8.1. ~~included in the Reliability Coordinator's restoration plan were invited in accordance with Requirement R10.~~

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The current restoration plan and any restoration plans in force since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in force for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.
- The current, approved restoration plan and any restoration plans in force for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
- ~~If there has been a restoration event, implementation of its restoration plan on any occasion over a rolling 12-month period for Requirement R7, Measure M7.~~

- ~~If there has been a resynchronization of an islanded area, implementation of its restoration plan on any occasion over a rolling 12-month period for Requirement R8, Measure M8.~~
- Actual training program materials or descriptions for three calendar years for Requirements ~~R9~~R7, Measure ~~M9~~M7.
- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement ~~R10~~R8, Measure ~~M10~~M8.

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

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

1.2. Compliance Monitoring and Enforcement Processes Program

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

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

Additional Compliance Information: None

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Reliability Coordinator failed to include one ~~sub-~~ requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two ~~sub-~~ requirement~~s~~ parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the ~~sub-~~requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the ~~sub-~~ requirement~~s~~ parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within ~~13~~ 15 calendar months of the last review.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.~~The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 60 calendar days.~~	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.~~The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 90 calendar days.~~	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.~~The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 120 calendar days.~~	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.~~The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 120 calendar days.~~
R5.	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans from its Transmission Operators and neighboring Reliability Coordinators for

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	approve/disapprove the plans within 45 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	approve/disapprove the plans within 60 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	approve/disapprove the plans within 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the ~~implementation~~ effective date.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~implementation~~ effective date.	
~~R7.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not work with its affected Generator Operators and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits.~~ ~~OR~~ ~~When the restoration plan cannot be completed as expected, the Reliability Coordinator did not utilize its restoration plan strategies to facilitate System restoration.~~
~~R8.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator did not coordinate or~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators.~~ ~~OR~~ ~~If the resynchronization could not be completed as expected, the Reliability Coordinator did not utilize its restoration plan strategies to facilitate resynchronization.~~
~~R9~~R7.	N/A	N/A	The Reliability Coordinator included the ~~annual~~ System restoration training at least once each 15 calendar months within its operations training program, but did not address both of the ~~sub-~~ requirement~~s~~ parts.	The Reliability Coordinator did not include the ~~annual~~ System restoration training at least once each 15 calendar months within its operations training program.
~~R10~~R8.	The Reliability Coordinator only held one restoration	The Reliability Coordinator did not ~~invite~~ request each	N/A	The Reliability Coordinator did not hold a restoration

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	drill, exercise, or simulation during the calendar year.	applicable ~~a~~ Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation within two calendar years.		drill, exercise, or simulation during the calendar year.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	Nov. 1, 2006	Adopted by Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	

Rationale

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-008-2 – Loss of Control Center Functionality**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to have an Operating Plan for backup facilities. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an Operating Plan for backup functionality that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** There is a similar requirement (Requirement R1) in EOP-005-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the creation of a plan: EOP-005-2 for a restoration plan and EOP-008-2 for a backup plan. The VRF assigned to EOP-008-1, Requirement R1 is lower than EOP-005-2, Requirement R1. The SDT recognizes that the VRF for EOP-008-1, Requirement R1 is lower than the VRF for the similar requirement in EOP-005-2 which is assigned a High VRF, however the SDT and stakeholders support the Medium VRF based on NERC's criteria for VRFs. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to create an Operating Plan for backup functionality. While the SDT agrees that, under some circumstances, it is possible that a failure to have an Operating Plan for backup functionality may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to have an Operating Plan for backup functionality would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to have an Operating Plan for backup functionality, it would still be expected to handle the situation if it occurred.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to have an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to have an Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-008-2, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.

VRF Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1 with some minor edits. The VSL's for R1 were revised slightly by replacing "Part" with "part". The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that requires entities to shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. This is 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the entity to have the Operating Plan for backup functionality at its primary and backup control centers. This is consistent with FERC guideline G1 regarding operating tools and backup facilities, however this requirement is administrative in nature.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 is unchanged from EOP-008-1, Requirement R2 and the VRF remains as Lower.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a copy of the Operating Plan for backup functionality at each of its control locations should not have an adverse impact on the bulk power system because operations at the different locations should be essentially identical. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.

VSL Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R3	
Proposed VRF	**High**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R3 is unchanged from EOP-008-1, Requirement R3 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) will impact the situational awareness of the Reliability Coordinator, and thus could affect the Reliability Coordinator's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Reliability Coordinator is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality.

VSL Justifications for EOP-008-2, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Reliability Coordinator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R4	
Proposed VRF	**High**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Balancing Authority or Transmission Operator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R4 is unchanged from EOP-008-1, Requirement R4 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have backup functionality (provided either through a facility or contracted services) will impact the situational awareness of the Transmission Operator or Balancing Authority, and thus could affect the Transmission Operator's or Balancing Authority's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Transmission Operator or Balancing Authority is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively.

VSL Justifications for EOP-008-2, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is binary and is at the Severe level. The requirement specifies that a Balancing Authority or Transmission Operator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Balancing Authority or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to update an Operating Plan for backup facilities annually. The assignment of the Medium VRF was made based on the premise that failure to annually update an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the annual review of the Operating Plan for back up functionality that is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has one part that is related to the main requirement regarding updating the Operating Plan and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R5 is unchanged from EOP-008-1, Requirement R5 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to update an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R5			
Lower	**Moderate**	**High**	**Severe**
The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.

VSL Justifications for EOP-008-2, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that, if violated, could prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the independence between the primary and back up control centers. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures. This is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R6 is unchanged from EOP-008-1, Requirement R46and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R6 addresses the situation applicable entities primary and backup capabilities can't depend on each other. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

VSL Justifications for EOP-008-2, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R6 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator, Balancing Authority, or Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. The Reliability Coordinator, Balancing Authority, or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires entities to conduct and document the results of an annual test of its backup facility. Violation of this requirement is not likely to cause bulk electric system instability, separation, or a cascading sequence of failures and is therefore assigned a Medium VRF consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R7 is unchanged from EOP-008-1, Requirement R7 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** EOP-008-1, Requirement R7 mandates testing of an applicable entity's Operating Plan for backup capability. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did not test their Operating Plan for backup capability it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R7			
Lower	**Moderate**	**High**	**Severe**
The responsible entity conducted an annual test of its Operating Plan for backup functionality, but it did not document the results. OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours, but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours, but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.

VSL Justifications for EOP-008-2, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the entity that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months to provide a plan to its Regional Entity showing how it will re-establish primary or backup functionality. If an entity fails to provide a plan to the Regional Entity, this violation in and of itself is not likely to cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. This is consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R8 is unchanged from EOP-008-1, Requirement R8 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R8 mandates that entities provide a plan for re-establishing backup capabilities following a catastrophic failure. A failure to provide this plan does not affect the applicable entity's ability to effectively monitor and control the bulk power system. Violation of this requirement is unlikely, by itself, to lead to bulk power system instability, separation, or cascading failures, thus the assignment of a "Medium" VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted more than six calendar months, but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted in more than seven calendar months, but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

VSL Justifications for EOP-008-2, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standard Audit Worksheet[1]

EOP-006-3 – System Restoration Coordination

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	RC	RP	RSG	TO	TOP	TP	TSP
R1								X						
R2								X						
R3								X						
R4								X						
R5								X						
R6								X						
R7								X						
R8								X						

DRAFT

[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. 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.
[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			
R7			
R8			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

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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)

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R1 Supporting Evidence and Documentation

R1. Each Reliability Coordinator shall develop, maintain, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include:

1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

1.2. Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with adjacent Transmission Operators in other Reliability Coordinator Areas, and with adjacent Reliability Coordinators.

1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.

1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

1.6. Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

Registered Entity Response (Required):

Question: Has the entity experienced a Disturbance that required it to implement its restoration plan?

☐ **Yes** ☐ **No**

Provide an explanation in the Compliance Narrative section.

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

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Evidence Requested[3]:

Provide the following evidence, or other evidence to demonstrate compliance.
The entity's most recent restoration plan with revision history
List of dates and times that Disturbances have occurred (if any)
Evidence that the restoration plan was implemented during Disturbances

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-006-3, R1

This section to be completed by the Compliance Enforcement Authority

	Verify the entity has developed and maintained a Reliability Coordinator Area restoration plan.
	Verify the scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area.
	Verify the scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and it its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas.
	Verify that the restoration plan was implemented (such as during Disturbances)
	Verify the restoration plan includes:
	(Part 1.1) A description of the high-level strategy for restoring the Interconnection.
	(Part 1.1) Minimum criteria to meet the objectives of the plan.
	(Part 1.2) Criteria and conditions are included in the restoration plan for reestablishing interconnections with:
	(Part 1.2) Other Transmission Operators within its Reliability Coordinator Area.
	(Part 1.2) Adjacent Transmission Operators in other Reliability Coordinator Areas.
	(Part 1.2) Other adjacent Reliability Coordinators.
	(Part 1.3) Reporting requirements for entities within the Reliability Coordinator Area during a restoration event.

3 Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	(Part 1.4) Criteria for sharing information regarding restoration with:
	(Part 1.4) Neighboring Reliability Coordinators.
	(Part 1.4) Transmission Operators within its Reliability Coordinator Area.
	(Part 1.4) Balancing Authorities within its Reliability Coordinator Area.
	(Part 1.5) Identification of the Reliability Coordinator as the primary contact for disseminating restoration information regarding restoration to:
	(Part 1.5) Neighboring Reliability Coordinators.
	(Part 1.5) Transmission Operators within its Reliability Coordinator Area.
	(Part 1.5) Balancing Authorities within its Reliability Coordinator Area.
	(Part 1.6) Criteria for transferring operations and authority back to the Balancing Authority.
Note to Auditor:	

Auditor Notes:

DRAFT

R2 Supporting Evidence and Documentation

R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision.

M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
The entity's most recent restoration plan with dated revision history
Evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-006-3, R2

This section to be completed by the Compliance Enforcement Authority

	Distribution of the Reliability Coordinator Area restoration plan to:
	Each of its Transmission Operators within 30 calendar days of creation/revision.
	Each of its Neighboring Reliability Coordinators within 30 calendar days of creation/revision.

Note to Auditor: Evidence may include but is not limited to electronic receipts, posting to a secure web site with notification to affected entities, or registered mail receipts.

Auditor Notes:

DRAFT

R3 Supporting Evidence and Documentation

R3. Each Reliability Coordinator shall review its restoration plan within 15 calendar months of the last review.

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 15 calendar months of the last review in accordance with Requirement R3.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence of entity's review of its restoration plan

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-006-3, R3

This section to be completed by the Compliance Enforcement Authority

	Reviewed its restoration plan within 15 calendar months of the last review.
Note to Auditor: Evidence may include but is not limited to a dated signature sheets, or revision histories.	

Auditor Notes:

DRAFT

R4 Supporting Evidence and Documentation

R4. Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt:

4.1 If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of written notification.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within 30 calendar days in accordance with Requirement R4.

Registered Entity Response (Required):
Question: Were conflicts between restoration plans identified? If yes, was the conflict resolved within the 30 calendar day limit? ☐ Yes ☐ No
Provide an explanation in the Compliance Narrative section.

Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-006-3, R4

This section to be completed by the Compliance Enforcement Authority

	The entity responded to the applicability question and provided evidence of compliance if the response was 'yes.'
	Neighboring Reliability Coordinator's restoration plans were reviewed within 60 calendar days of receipt.
	Written notification of any conflicts discovered were provided within 60 calendar days of receipt.
	(Part 4.1) Any conflicts were resolved within 30 calendar days of written notification.
Note to Auditor:	

Auditor Notes:

DRAFT

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area.

5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

M5. Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-006-3, R5

This section to be completed by the Compliance Enforcement Authority

	Verify the entity reviewed the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area.
	(Part 5.1) Verify the entity determined the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operator's restoration plans within its Reliability Coordinator Area.
	(Part 5.1) Determine that approval or disapproval, with stated reasons, was provided to the Transmission Operator(s) within 30 calendar days of receipt of the plan(s).
Note to Auditor:	

Auditor Notes:

DRAFT

R6 Supporting Evidence and Documentation

R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date.

M6. Each Reliability Coordinator shall have documentation such as electronic receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the effective date in accordance with Requirement R6.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Latest entity approved restoration plan for itself and for all Transmission Operators within its Reliability Coordinator Area
Location of its and each Transmission Operator's restoration plan within the entity's primary and backup control rooms

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-006-3, R6

This section to be completed by the Compliance Enforcement Authority

	Verify the entity has a copy of its latest restoration Plan prior to the effective date:

	Within the primary control room.
	Within the backup control room.
	Verify the entity has a copy of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area prior to the effective date:
	Within the primary control room.
	Within the backup control room.
Note to Auditor:	

Auditor Notes:

DRAFT

R7 Supporting Evidence and Documentation

R7. Each Reliability Coordinator shall include within its operations training program, at least once each 15 calendar months, System restoration training for its System Operators. This training program shall address the following:

7.1. The coordination role of the Reliability Coordinator

7.2. Re-establishing the Interconnection

M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Electronic copy or hard copy of its training records available showing that it has provided System restoration training for the entity's System Operators

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-006-3, R7

This section to be completed by the Compliance Enforcement Authority

	The entity included System restoration training for its System Operators within its operations training program at least once each 15 calendar months.
	Verify the training program addresses:

	(Part 7.1) Reliability Coordinator coordination role.
	(Part 7.2) Reestablishing the Interconnection.
Note to Auditor: Actual performance of the training is covered under PER-005.	

Auditor Notes:

DRAFT

R8 Supporting Evidence and Documentation

R8. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted.

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

M8. Each Reliability Coordinator shall have evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year in accordance with Requirement R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement R8 and R8 Part 8.1.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year
Evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate at least once every two calendar years

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-006-3, R8

This section to be completed by the Compliance Enforcement Authority

	Verify the entity conducted two System restoration drills, exercises, or simulations each calendar year.
	Verify the entity included the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that was being conducted.
	Verify the entity requested each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least every two calendar years.
Note to Auditor:	

Auditor Notes:

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Additional Information:

Reliability Standard

The full text of EOP-006-3 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

Still needed. Order No. 749, 134 FERC ¶ 61,215 (2011)

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	7/8/16	NERC Compliance Assurance, RSAW Task Force	New Document

DRAFT

Standard Development Timeline

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

Description of Current Draft

EOP-008-2 is being posted for a 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	July 15, 2015
SAR posted for comment	07/21/2015 – 08/19/2015

Anticipated Actions	Date
45-day formal comment period with ballot	06/22/2016 – 08/08/2016
45-day formal comment period with additional ballot	08/30/2016 – 10/14/2016
10-day final ballot	11/01/2016 – 11/11/2016
NERC Board (Board) adoption	February 2017

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

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

A. Introduction

1. **Title:** Loss of Control Center Functionality
2. **Number:** EOP-008-~~1~~2
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Operator
     - **4.1.3.** Balancing Authority
5. **Effective Date:** ~~The first day of the first calendar quarter twenty four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty four months after Board of Trustees adoption.~~ See the Implementation Plan for EOP-008-2.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. ~~-~~This Operating Plan for backup functionality shall include ~~the following, at a minimum~~: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- **1.1.** The location and method of implementation for providing backup functionality ~~for the time it takes to restore the primary control center functionality~~.
- **1.2.** A summary description of the elements required to support the backup functionality. These elements shall include~~, at a minimum~~:
  - **1.2.1.** Tools and applications to ensure that System Operators have situational awareness of the BES.
  - **1.2.2.** Data communications.
  - **1.2.3.** ~~Voice~~ Interpersonal ~~communications~~Communications.
  - **1.2.4.** Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. ~~-~~The Operating Process shall include ~~at a minimum~~:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in ~~force~~ effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in ~~force~~ effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. ~~-~~To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less

- Unplanned outages of the primary or backup facilities

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. ~~-~~To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall ~~annually~~ review and approve its Operating Plan for backup functionality at least once every 15 calendar months. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~–~~to any part of the Operating Plan described in Requirement R1.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator~~,~~ shall have evidence that its dated, current, and in ~~force~~ effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved ~~annually~~ at least once every 15 calendar months and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct ~~and document results of an annual~~ a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall ~~that~~ demonstrate~~s~~: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its ~~annual~~ test of its Operating Plan for backup functionality, in accordance with Requirement R7.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

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

mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

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

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

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in force Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved ~~annually~~ at least once every 15 calendar months and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current and previous calendar years ~~and one previous year~~, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's six ~~Parts~~ parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's six ~~Parts~~ parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three of the requirement's six ~~Parts~~ parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six ~~Parts~~ parts (Requirement R1, Parts 1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.
R2.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality.
R4.	N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				center functionality respectively.
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was ~~annually~~ reviewed and approved at least once every 15 calendar months. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to maintain compliance with Reliability Standards.
R7.	The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but it did not document the results. OR, The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months. OR, The responsible entity conducted ~~an annual~~a test of its Operating Plan for backup functionality at least once every 15 calendar months, but the test was for less than 0.5 continuous hours.
R8.	The responsible entity experienced a loss of its	The responsible entity experienced a loss of its	The responsible entity experienced a loss of its	The responsible entity experienced a loss of its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	2009 - 2010	Project 2006-04: Revisions	Major re-write to accommodate changes noted in project file
1	August 5, 2010	Project 2006-04: Adopted by the Board	
1	April 21, 2011	Project 2006-04: FERC Order issued approving EOP-008-1 (approval effective June 27, 2011)	
1	July 1, 2013	Project 2006-04: Updated VRFs and VSLs based on June 24, 2013 approval	

Rationale

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-08 Emergency Operations

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **EOP-008-2 – Loss of Control Center Functionality**. Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines. The Emergency Operations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to have an Operating Plan for backup facilities. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report**

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	R1 requires the entity to have an Operating Plan for backup functionality that is consistent with FERC guideline G1 regarding Operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** There is a similar requirement (Requirement R1) in EOP-005-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the creation of a plan: EOP-005-2 for a restoration plan and EOP-008-2 for a backup plan. The VRF assigned to EOP-008-1, Requirement R1 is lower than EOP-005-2, Requirement R1. The SDT recognizes that the VRF for EOP-008-1, Requirement R1 is lower than the VRF for the similar requirement in EOP-005-2 which is assigned a High VRF, however the SDT and stakeholders support the Medium VRF based on NERC's criteria for VRFs. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to create an Operating Plan for backup functionality. While the SDT agrees that, under some circumstances, it is possible that a failure to have an Operating Plan for backup functionality may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to have an Operating Plan for backup functionality would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to have an Operating Plan for backup functionality, it would still be expected to handle the situation if it occurred.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk

VRF Justifications for EOP-008-2, R1	
Proposed VRF	**Medium**
	power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to have an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to have an Operating Plan. Since the requirement has only one objective, only one VRF was assigned.

VSLs for EOP-008-2, R1			
Lower	**Moderate**	**High**	**Severe**
The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.

VRF Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1 with some minor edits. The VSL's for R1 were revised slightly by replacing "Part" with "part". The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in an Operations Planning time frame that requires entities to shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. This is 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.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 requires the entity to have the Operating Plan for backup functionality at its primary and backup control centers. This is consistent with FERC guideline G1 regarding operating tools and backup facilities, however this requirement is administrative in nature.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R2 is unchanged from EOP-008-1, Requirement R2 and the VRF remains as Lower.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a copy of the Operating Plan for backup functionality at each of its control locations should not have an adverse impact on the bulk power system because operations at the different locations should be essentially identical. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.

VSL Justifications for EOP-008-2, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R3	
Proposed VRF	**High**
NERC VRF Discussion	R3 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 requires the Reliability Coordinator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R3 is unchanged from EOP-008-1, Requirement R3 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) will impact the situational awareness of the Reliability Coordinator, and thus could affect the Reliability Coordinator's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Reliability Coordinator is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality.

VSL Justifications for EOP-008-2, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R3 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Reliability Coordinator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R4	
Proposed VRF	**High**
NERC VRF Discussion	R4 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 requires the Balancing Authority or Transmission Operator to have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. A high VRF was assigned consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R4 is unchanged from EOP-008-1, Requirement R4 and the VRF remains as High.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to have backup functionality (provided either through a facility or contracted services) will impact the situational awareness of the Transmission Operator or Balancing Authority, and thus could affect the Transmission Operator's or Balancing Authority's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Transmission Operator or Balancing Authority is required to maintain control and awareness of the bulk power system at all times.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively.

VSL Justifications for EOP-008-2, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is binary and is at the Severe level. The requirement specifies that a Balancing Authority or Transmission Operator must have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. The Balancing Authority or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time to update an Operating Plan for backup facilities annually. The assignment of the Medium VRF was made based on the premise that failure to annually update an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 requires the annual review of the Operating Plan for back up functionality that is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has one part that is related to the main requirement regarding updating the Operating Plan and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R5 is unchanged from EOP-008-1, Requirement R5 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to update an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to update an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R5			
Lower	**Moderate**	**High**	**Severe**
The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.

VSL Justifications for EOP-008-2, R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R5	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	R6 is a requirement in an Operations Planning time frame that, if violated, could prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 requires the independence between the primary and back up control centers. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures. This is consistent with FERC guideline G1 regarding operating tools and backup functionality.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R6 is unchanged from EOP-008-1, Requirement R46and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R6 addresses the situation applicable entities primary and backup capabilities can't depend on each other. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

VSL Justifications for EOP-008-2, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R6 is binary and is at the Severe level. The requirement specifies that a Reliability Coordinator, Balancing Authority, or Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. The Reliability Coordinator, Balancing Authority, or Transmission Operator will either have a backup facility that meets the requirement or they will not. Therefore, a binary VSL of Severe is justified. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R6	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R7	
Proposed VRF	**Medium**
NERC VRF Discussion	R7 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires entities to conduct and document the results of an annual test of its backup facility. Violation of this requirement is not likely to cause bulk electric system instability, separation, or a cascading sequence of failures and is therefore assigned a Medium VRF consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R7 is unchanged from EOP-008-1, Requirement R7 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** EOP-008-1, Requirement R7 mandates testing of an applicable entity's Operating Plan for backup capability. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did not test their Operating Plan for backup capability it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R7			
Lower	**Moderate**	**High**	**Severe**
The responsible entity conducted an annual test of its Operating Plan for backup functionality, but it did not document the results. OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours, but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours, but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.

VSL Justifications for EOP-008-2, R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF Justifications for EOP-008-2, R8	
Proposed VRF	**Medium**
NERC VRF Discussion	R8 is a requirement in an Operations Planning time frame that, if violated, could directly prevent restoration to normal operations, cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 requires the entity that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months to provide a plan to its Regional Entity showing how it will re-establish primary or backup functionality. If an entity fails to provide a plan to the Regional Entity, this violation in and of itself is not likely to cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. This is consistent with FERC guideline G1 regarding operating tools and backup facilities.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no parts and only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** Requirement R8 is unchanged from EOP-008-1, Requirement R8 and the VRF remains as Medium.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Requirement R8 mandates that entities provide a plan for re-establishing backup capabilities following a catastrophic failure. A failure to provide this plan does not affect the applicable entity's ability to effectively monitor and control the bulk power system. Violation of this requirement is unlikely, by itself, to lead to bulk power system instability, separation, or cascading failures, thus the assignment of a "Medium" VRF.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective and only one VRF was assigned.

VSLs for EOP-008-2, R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted more than six calendar months, but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality, but the plan was submitted in more than seven calendar months, but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

VSL Justifications for EOP-008-2, R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The Requirements of EOP-008-2 deal with having an Operating Plan to address the loss of control center functionality and mirrors the Requirements of EOP-008-1. The VSL's for this requirement meet the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VSL Justifications for EOP-008-2, R8	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standard Audit Worksheet[1]

EOP-008-2 – Loss of Control Center Functionality

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	RC	RP	RSG	TO	TOP	TP	TSP
R1	X							X				X		
R2	X							X				X		
R3								X						
R4	X											X		
R5	X							X				X		
R6	X							X				X		
R7	X							X				X		
R8	X							X				X		

[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. 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.
[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

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Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			
R7			
R8			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

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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)

DRAFT

R1 Supporting Evidence and Documentation

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include:

1.1. The location and method of implementation for providing backup functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data communications.

1.2.3. Interpersonal Communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated, current, and in effect Operating Plan for backup functionality in electronic or hardcopy format

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-008-2, R1

This section to be completed by the Compliance Enforcement Authority

	Verify that the Operating Plans for backup functionality specifically address each one of the following elements:
	(Part 1.1) The location and method of implementation for providing backup functionality.
	(Part 1.2) A summary description of the elements required to support the backup functionality. These elements shall include:
	(Part 1.2.1) Tools and applications to ensure that System Operators have situational awareness of the BES.
	(Part 1.2.2) Data communications.
	(Part 1.2.3) Interpersonal Communications.
	(Part 1.2.4) Power source(s).
	(Part 1.2.5) Physical and cyber security.
	(Part 1.3) An Operating Process for keeping the backup functionality consistent with the primary control center.
	(Part 1.4) Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.
	(Part 1.5) Verify the transition period between the loss of primary control center functionality and the time to fully implement the backup functionality is less than or equal to two hours.
	(Part 1.6) An Operating Process that includes:
	(Part 1.6) Description of the actions to be taken during the transition period between the loss of primary

	control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2.
	(Part 1.6.1) A list of all entities to notify when there is a change in operating locations.
	(Part 1.6.2) Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.
	(Part 1.6.3) Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.
Note to Auditor:	

Auditor Notes:

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R2 Supporting Evidence and Documentation

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated, current, and in effect copy of the entity's Operating Plan for backup functionality
Location of the entity's primary control center and the location providing backup functionality

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-008-2, R2

This section to be completed by the Compliance Enforcement Authority

	Verify that a current set of the entities backup functionality Operating Plan is available at both the primary control center and the backup facility location.
Note to Auditor:	

Auditor Notes:

DRAFT

R3 Supporting Evidence and Documentation

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during:

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated evidence showing the entity has a backup control center facility

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-008-2, R3

This section to be completed by the Compliance Enforcement Authority

	Verify that the entity has a backup control center (of its own, or at another entity's control center).
	Verify the backup control center is staffed by Reliability Coordinator certified operators when control has been transferred to the backup center.
	Verify the backup facility provides the same functionality to maintain compliance with the Reliability Standards as the primary control center.
	If there was a planned outage of the primary or backup facilities for longer than two weeks, verify the entity had a backup facility during the planned outage.
Note to Auditor:	

Auditor Notes:

DRAFT

R4 Supporting Evidence and Documentation

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during:

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated evidence showing the entity has backup functionality

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-008-2, R4

This section to be completed by the Compliance Enforcement Authority

	Verify the entity's backup control center contains the functionality as listed below sufficient for maintaining compliance with all Reliability Standards that depend on primary control center functionality for reliability of the BES:
	Monitoring.
	Control.
	Logging.
	Alarming.
	If there was a planned outage of the primary or backup facilities for longer than two weeks, verify the entity had backup functionality during the planned outage.
Note to Auditor:	

Auditor Notes:

DRAFT

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall review and approve its Operating Plan for backup functionality at least once every 15 calendar months.

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence that its dated, current, and in effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved at least once every 15 calendar months and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
The entity's dated, current, and in effect Operating Plan for backup functionality, in electronic or hardcopy format

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-008-2, R5

This section to be completed by the Compliance Enforcement Authority

	Verify the entity provided evidence that it reviewed, updated, and approved its backup functionality Operating Plan at least once every 15 calendar months.
	Verify that any updates and approvals of the Operating Plan took place within sixty days of any changes to the Operating Plan as described in R1.
Note to Auditor:	

Auditor Notes:

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R6 Supporting Evidence and Documentation

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-008-2, R6

This section to be completed by the Compliance Enforcement Authority

	Verify that the primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards
Note to Auditor: Possible evidence could include network block diagrams showing discreet communication paths.	

Auditor Notes:

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R7 Supporting Evidence and Documentation

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall demonstrate:

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its test of its Operating Plan for backup functionality, in accordance with Requirement R7.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
Evidence such as dated records, that the entity has completed and documented its test of its Operating Plan for backup functionality

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-008-2, R7

This section to be completed by the Compliance Enforcement Authority

	Verify the entity conducted a test of its Operating Plan at least once every 15 calendar months and documented the results.
	(Part 7.1) Verify the transition time was documented to identify the time from loss of functionality of the primary system and the time that the backup was fully functional.
	(Part 7.2) Verify the backup facility was operated for a minimum of two continuous hours during the test.
Note to Auditor:	

Auditor Notes:

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R8 Supporting Evidence and Documentation

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality.

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

Registered Entity Response (Required):

Question: Has the Registered Entity experienced a loss of primary or backup control center functionality for longer than six calendar months or anticipated this loss will last for more than six calendar months? ☐ Yes ☐ No

Provide an explanation in the Compliance Narrative section.

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[i]:

Provide the following evidence, or other evidence to demonstrate compliance.
If applicable, evidence that a plan has been submitted to the entity's Regional Entity within six calendar months of the date when the functionality was lost showing how the entity will re-establish primary or backup functionality

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-008-2, R8

This section to be completed by the Compliance Enforcement Authority

	Responded to the applicability Question and provided evidence of compliance if the response was yes.
	Verify the entity provided evidence to the Regional Entity of a plan detailing how it will re-establish primary or backup functionality within six calendar months of the date functionality is lost, for a loss of functionality anticipated to be six months or more.
Note to Auditor:	

Auditor Notes:

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Additional Information:

Reliability Standard

The full text of EOP-008-2 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

Still needed. Order No. 749, 134 FERC ¶ 61,215 (2011)

Selected Glossary Terms

The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Demand: 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: 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.

Net Energy for Load: 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.

Total Internal Demand: The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	7/8/16	NERC Compliance Assurance, RSAW Task Force	New Document

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

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Implementation Plan

Project 2015-08 Emergency Operations
Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2

Applicable Standards

- EOP-005-3 — System Restoration from Blackstart Resources
- EOP-006-3 — System Restoration Coordination
- EOP-008-2 — Loss of Control Center Functionality

Requested Retirements

- EOP-005-2 — System Restoration from Blackstart Resources
- EOP-006-2 — System Restoration Coordination
- EOP-008-1 — Loss of Control Center Functionality

Prerequisite Standards

None

Applicable Entities

- Transmission Operators
- Generator Operators
- Transmission Owners identified in the Transmission Operators Restoration Plan
- Distribution Providers identified in the Transmission Operators Restoration Plan
- Reliability Coordinators
- Balancing Authority

Background

Implementation of revisions and retirements recommended by the Project 2015-02 Emergency Operations Periodic Review Team clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards and apply Paragraph 81 criteria, while making the standards more Results-based and addressing the outstanding directive from FERC Order No. 749.

Effective Date

EOP-005-3 — System Restoration from Blackstart Resources
Where approval by an applicable Governmental Authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-006-3 — System Restoration Coordination
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

EOP-008-2 — Loss of Control Center Functionality
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definition
None

Retirement Date

EOP-005-2 — System Restoration from Blackstart Resources
Reliability Standard EOP-005-2 shall be retired immediately prior to the effective date of EOP-005-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-006-2 — System Restoration Coordination

Reliability Standard EOP-006-2 shall be retired immediately prior to the effective date of EOP-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

EOP-008-1 — Loss of Control Center Functionality

Reliability Standard EOP-008-1 shall be retired immediately prior to the effective date of EOP-008-2 in the particular jurisdiction in which the revised standard is becoming effective.

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Mapping Document

Project 2015-08 Emergency Operations

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R1 **R1.** Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shut down area to service, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: [Violation Risk Factor = High] [Time Horizon = Operations Planning]	EOP-005-3, Requirement R1 **R1.** Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*	EOP-005-3, Requirement R1 In this industry it is widely understood that "*have a restoration plan*," is not simply to be in possession of a restoration plan. The intent of the EOP SDT is for the TOP to develop its restoration plan and for the restoration plan to be utilized. The EOP SDT removed the language: "*…to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System*" in Requirement R1, as it is covered in Requirement R1, Part 1.8. Due to the addition of the word "implement," the phrase, "Real-time Operations" was added to the Time Horizon.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-005-2, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R2 **R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that the approved restoration plan is provided to entities prior to its effective date, rather than prior to any given implementation date of the restoration plan.
EOP-005-2, Requirement R3 **R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* EOP-005-2, Requirement R3, Part 3.1 **3.1** If there are no changes to the previously submitted restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its	EOP-005-3, Requirement R3 R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator at least once each 15 calendar months on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	The language, "…at least once each 15 calendar months…" was added to provide clarity. Retirement of EOP-005-2, Requirement R3, and Part 3.1 was approved by FERC with an effective date of January 21, 2014.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary.		
EOP-005-2, Requirement R4 **R4.** Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R4 **R4.** Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	As previously written, Requirement R4 addressed (in one sentence) two restoration plan updates that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. This language creates two ambiguities. First, the phrase: "… that would change the implementation of its restoration plan" appeared to apply to both types of changes; however, no time frame is specified for updating the restoration plan for a planned BES modification. One could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		Second, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes is confusing. Some "system modifications" can include "BES modifications". Examples of unplanned System modifications could include natural disasters that affect BES Facilities, major equipment failures, etc., that are integral to the restoration plan. For clarity, the EOP SDT revise the language in this Requirement to require a TOP to update its restoration plan to only reflect System modifications that affect its ability to implement its restoration plan as describe in Requirement R1 Parts. The intent is not to capture minor modifications that would have no impact on the implementation of a restoration, such as element number changes or device changes that have no significance to the implementation of the plan.
EOP-005-2, Requirement R4, Part 4.1 **R4.1** Each Transmission Operator shall submit its revised restoration plan	EOP-005-3, Requirement R4, Parts 4.1 and 4.2	The EOP SDT revisions harmonize the use of "System modification" and clarify the timing

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
to its Reliability Coordinator for approval within the same 90 calendar day period.	**4.1.** No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications. **4.2.** No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.	for unplanned and planned System modifications.
EOP-005-2, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	EOP-005-3, Requirement R5 **R5.** Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	"Implementation date" was revised to "effective date" to clarify that System Operators will be in possession of the most current version of a restoration plan prior to that plan becoming effective, rather than prior to any given implementation date of a restoration plan.
EOP-005-2, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended	EOP-005-3, Requirement R6 **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its	The sentence, "This shall be completed every five years at a minimum" was revised to: "This shall be completed at least once every five years" to eliminate any ambiguity in the prior language.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*	
EOP-005-2, Requirement R7 **R7.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Transmission Operator shall implement its restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the Independent Experts Review Panel (IERP) recommendation to retire EOP-005-2, Requirement R7 as redundant. By adding the language: "develop and implement" to EOP-005-3, Requirement R1, EOP-005-2, Requirement R7, is redundant to EOP-005-3, Requirement R1.
EOP-005-2, Requirement R8 **R8.** Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize		The EOP SDT agrees with the IERP to retire EOP-005-2, Requirement R8 as "duplicative with EOP-005-2, Requirement R1, Part 1.3 (have a plan) and RC authority in IRO-001-1.1b, Requirement R3." The EOP SDT recommends retirement of EOP-005-2,

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		Requirement R8 under Criterion B7 as Redundant.
EOP-005-2, Requirement R10, and Requirement R10, Parts 10.1, 10.2, 10.3, and 10.4 **R10.** Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **10.1.** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **10.2.** Restoration priorities.	EOP-005-3, Requirement R8, and Requirement R, Parts 8.1, 8.2, 8.3, 8.4, and 8.5 **R8.** Each Transmission Operator shall include within its operations training program, System restoration training at least once each 15 calendar months for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **8.1** System restoration plan including coordination with the Reliability Coordinator and Generator Operators included in the restoration plan. **8.2** Restoration priorities.	The language, "…at least once each 15 calendar months…" was added to provide clarity and to align training with the timing for updates to the restoration plan. The language, "…to assure the proper execution of its restoration plan" was removed from this requirement, as it added no additional value. Requirement R8, Part 8.5 was added to Requirement R8 to address findings from the *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans*.

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
10.3. Building of cranking paths. **10.4.** Synchronizing (re-energized sections of the System).	**8.3** Building of cranking paths. **8.4** Synchronizing (re-energized sections of the System). **8.5** Transition to Balancing Authority for Area Control Error and Automatic Generation Control.	
EOP-005-2, Requirement R11 **R11.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-005-2, Requirement R9 **R9.** Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Federal Energy Regulatory Commission (Commission) Order no. 749: *"[N]ERC, in its comments about the term [unique tasks], states that it 'could promote the development of a guideline to aid registered entities in complying with Requirement R11.' The Commission notes that this Reliability Standard will not become effective for at least 24 months, during which time ambiguities in language or differences of opinion among affected entities may be resolved in practical ways. Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop*

Standard: EOP-005-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		a guideline to aid entities in their compliance obligations." The Project 2015-02 Emergency Operations Periodic Review Team, as well as the Project 2015-08 Emergency Operations Standards Drafting Team determined (through conducted outreach and comment questions/responses during postings of periodic review templates and the SAR) that industry does not find ambiguity with the term "unique tasks." The industry understands "unique tasks" to be those tasks that are defined by the TOP, TO, and the DP.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, 1.6, 1.7, 1.8 , and 1.9 **R1.** Each Reliability Coordinator shall have a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shut down area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]* **1.1** A description of the high level strategy to be employed during	EOP-006-3, Requirement R1, and Requirement R1, Parts 1.1, 1.2, 1.3, 1.4, 1.5, and 1.6 **R1.** Each Reliability Coordinator shall develop, maintain, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon*	Due to the addition of the language "implement," Real-time Operations was added to the Time Horizon. The language "adjacent" was added to distinguish between direct connection v. multiple neighbors (beyond direct connection). Requirement R1, Parts 1.2, 1.3, and 1.4 should be retired under Paragraph 81, Criterion B7, as redundant with Requirement R1, Part 1.5.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
restoration events for restoring the Interconnection including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Operating Processes for restoring the Interconnection. **1.3** Descriptions of the elements of coordination between individual Transmission Operator restoration plans. **1.4** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators. **1.5** Criteria and conditions for reestablishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.	*= Operations Planning, Real-time Operations]* **1.1** A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan. **1.2** Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with adjacent Transmission Operators in other Reliability Coordinator Areas, and with adjacent Reliability Coordinators. **1.3** Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.4** Criteria for sharing information regarding restoration with neighboring Reliability	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.6 Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. **1.7** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.8** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.9** Criteria for transferring operations and authority back to the Balancing Authority.	Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. **1.5** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area. **1.6** Criteria for transferring operations and authority back to the Balancing Authority.	

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-006-2, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review their neighboring Reliability Coordinator's restoration plans. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days.	EOP-006-3, Requirement R4, and Requirement R4, Part 4.1 **R4.** Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* **4.1** If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of written notification.	Language for timeframe and written notification was added for clarity.
EOP-006-2, Requirement R6 **R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the	EOP-006-3, Requirement R6 **R7.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the	"Implementation date" was revised to "effective date" for clarity.

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
implementation date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*	
EOP-006-2, Requirement R7 **R7.** Each Reliability Coordinator shall work with its affected Generator Operators~~,~~ and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R7 as "a logical action that does not require a standard." The EOP SDT recommends retirement of EOP-006-2, Requirement R7 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop, maintain, and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R7, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R8 **R8.** The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries		The EOP SDT agrees with the IERP to retire EOP-006-2, Requirement R8 as "a logical action that does not require a standard." The EOP SDT recommends retirement of

Standard: EOP-006-3		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*		EOP-006-2, Requirement R8 under Criterion A (Overreaching Criterion). In addition, by adding the language: "develop, maintain, and implement" to EOP-006-3, Requirement R1, EOP-006-2, Requirement R8, is redundant to EOP-006-3, Requirement R1.
EOP-006-2, Requirement R9 **R9.** Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-006-3, Requirement R7 **R7.** Each Reliability Coordinator shall include within its operations training program, at least once each 15 calendar months, System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	Language for timeframe was added for clarity. "To assure the proper execution of its restoration plan" was removed because it added no additional value; the entire standard is based upon using your restoration plan when needed.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
EOP-008-1, Requirement R1, Part 1.1 **1.1.** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.	EOP-008-2, Requirement R1, Part 1.1 **1.1** The location and method of implementation for providing backup functionality.	To provide clarification: Requirement R1, Part 1.1, it would be difficult to establish a timing requirement to restore primary control center functionality, given the range of events that could render the primary control center inoperable. The revision to Requirement R1, Part 1.1. prevents a tertiary (i.e., already included in EOP-008-2, Requirements R3 and R4).
EOP-008-1, Requirement R1, Part 1.2.3 **1.2.3** Voice communications.	EOP-008-2, Requirement R1, Part 1.2.3 **1.2.3** Interpersonal Communications	The COM-001-2 standard, along with the defined term "Interpersonal Communications" became effective 10/1/2015, therefore the EOP SDT agreed that this defined term should be used.
EOP-008-1, Requirement R5 **R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-008-2, Requirement R5 **R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall review and approve its Operating Plan for backup functionality at least once every 15 calendar months. *[Violation Risk Factor =*	The language, "…at least once each 15 calendar months…" was added to provide clarity.

Standard:EOP-008-2		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Medium] [Time Horizon = Operations Planning]	
EOP-008-1, Requirement R7 **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	EOP-008-1, Requirement R7 **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall demonstrate: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*	The language, "…at least once each 15 calendar months…" was added to provide clarity.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Benchmark Geomagnetic Disturbance Event Description

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

RELIABILITY | ACCOUNTABILITY





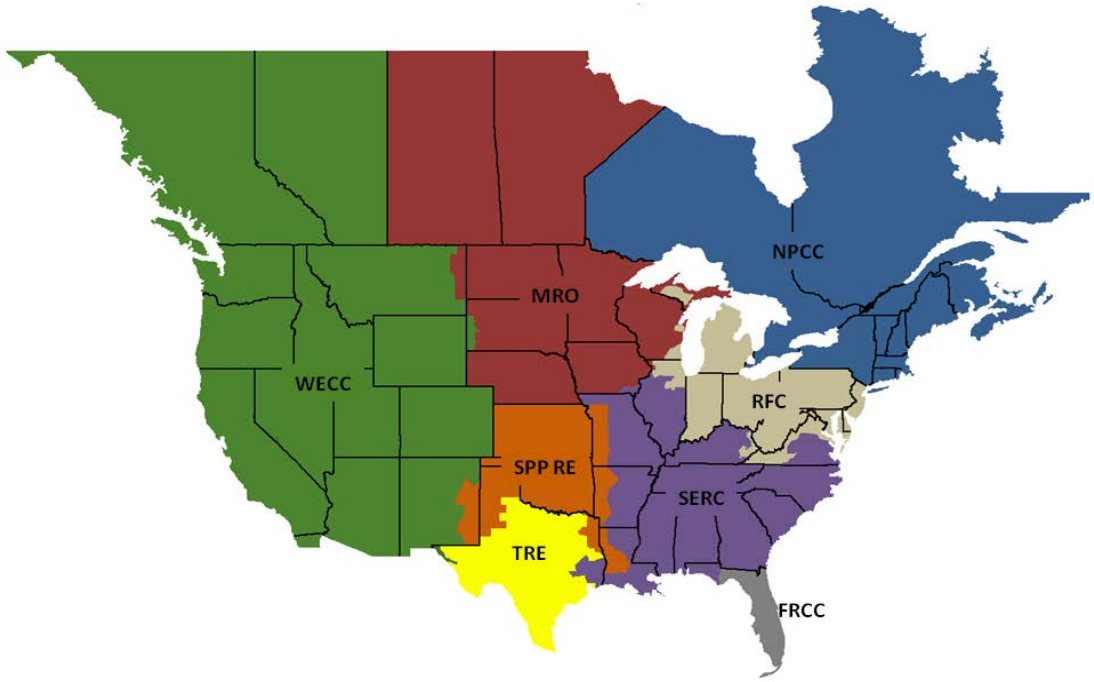

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Preface

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

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



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

Introduction

Background

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

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

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

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

General Characteristics

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

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

Benchmark GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [2]; thus, any benchmark event should consider the probability that the event will occur, as well as the impact or consequences of such an event. The benchmark event is composed of the following elements: 1) a reference peak geoelectric field amplitude (V/km) derived from statistical analysis of historical magnetometer data; 2) scaling factors to account for local geomagnetic latitude; 3) scaling factors to account for local earth conductivity; and 4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

Reference Geoelectric Field Amplitude

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

Table 1: Reference earth model (Quebec)

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

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

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

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

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

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure (see Appendix II).

Reference Geomagnetic Field Waveshape

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

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

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

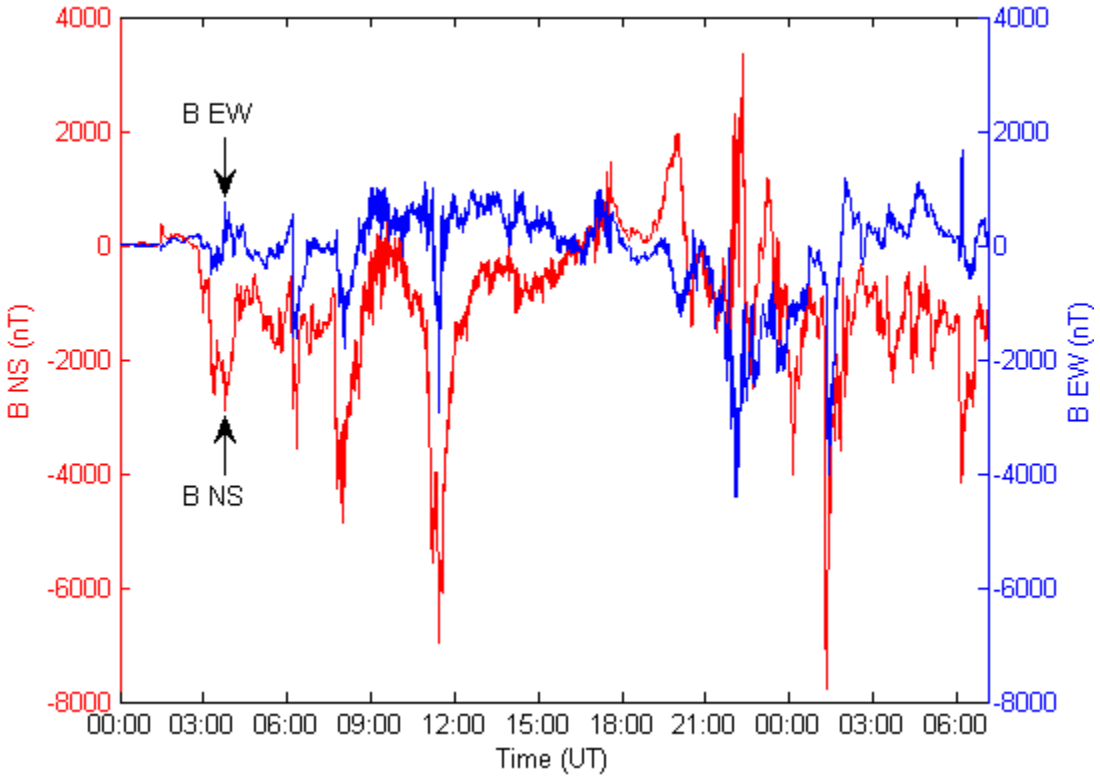


Figure 1: Benchmark Geomagnetic Field Waveshape
Red Bn (Northward), Blue Be (Eastward)
Referenced to pre-event quiet conditions

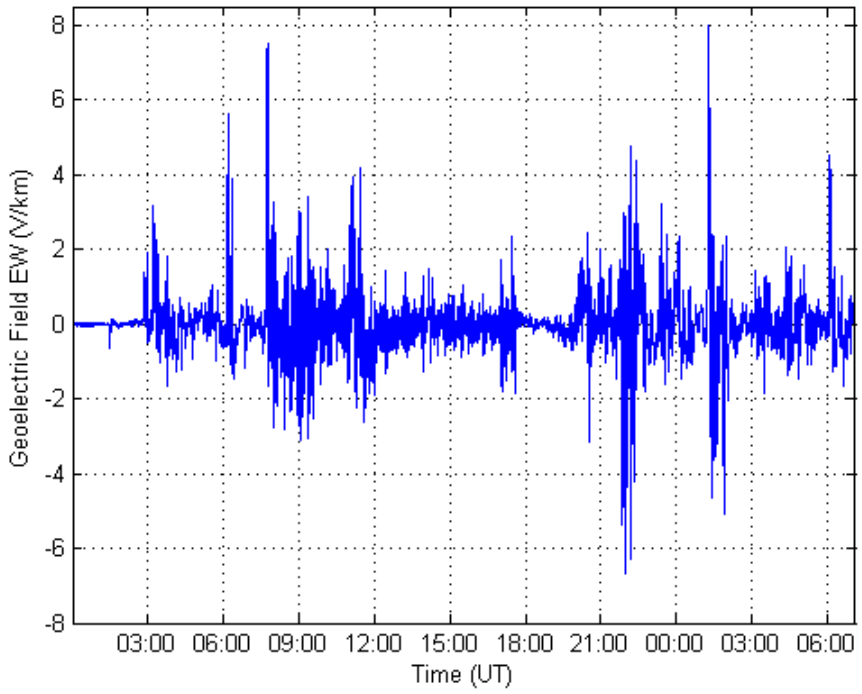


Figure 2: Benchmark Geoelectric Field Waveshape (E_E Eastward)

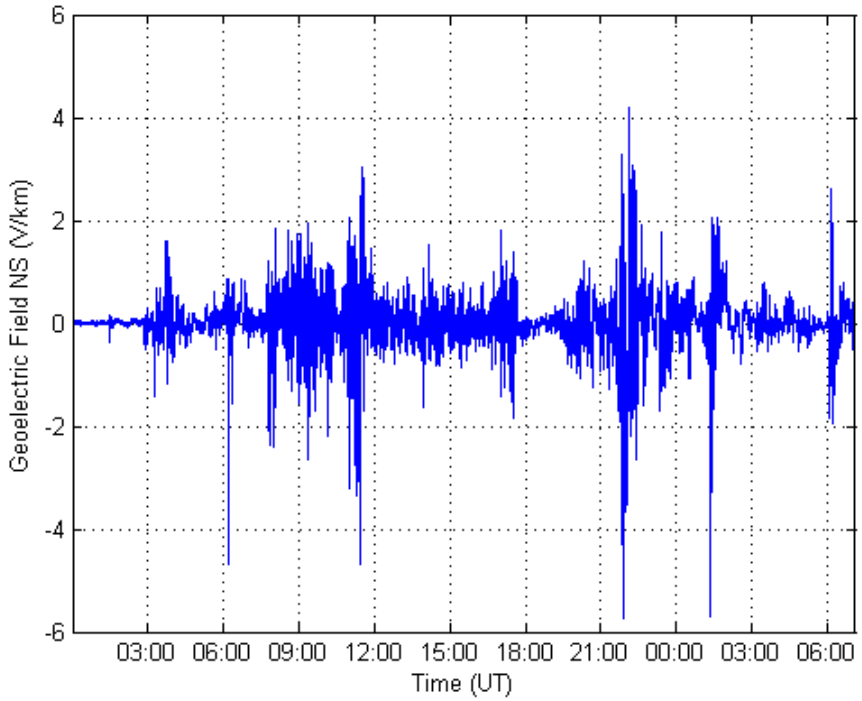


Figure 3: Benchmark Geoelectric Field Waveshape (E_N Northward)

Appendix I – Technical Considerations

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

Statistical Considerations

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

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

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

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

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

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

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

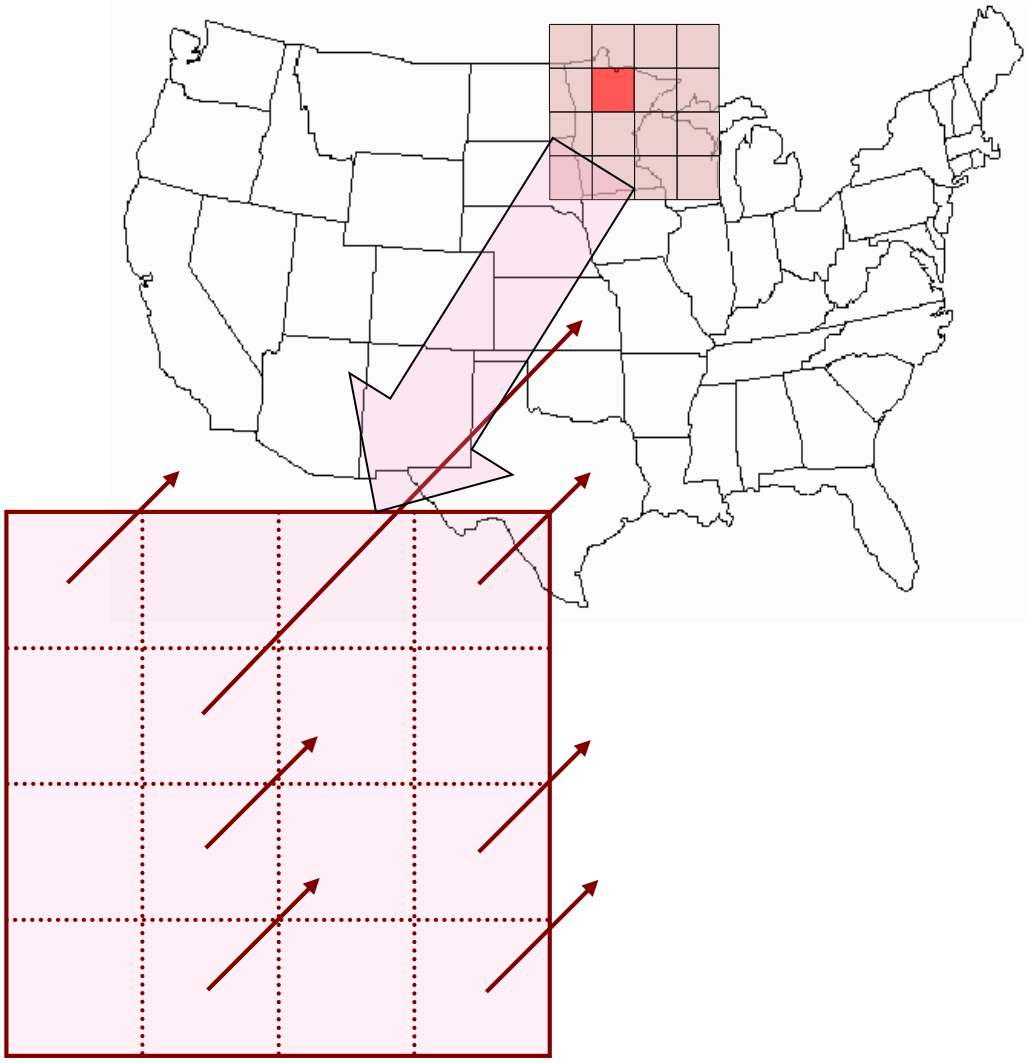


Figure I-1: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field Observed during a Strong Geomagnetic Storm.
In this illustration, the red square illustrates a spatially localized field enhancement.

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

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

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

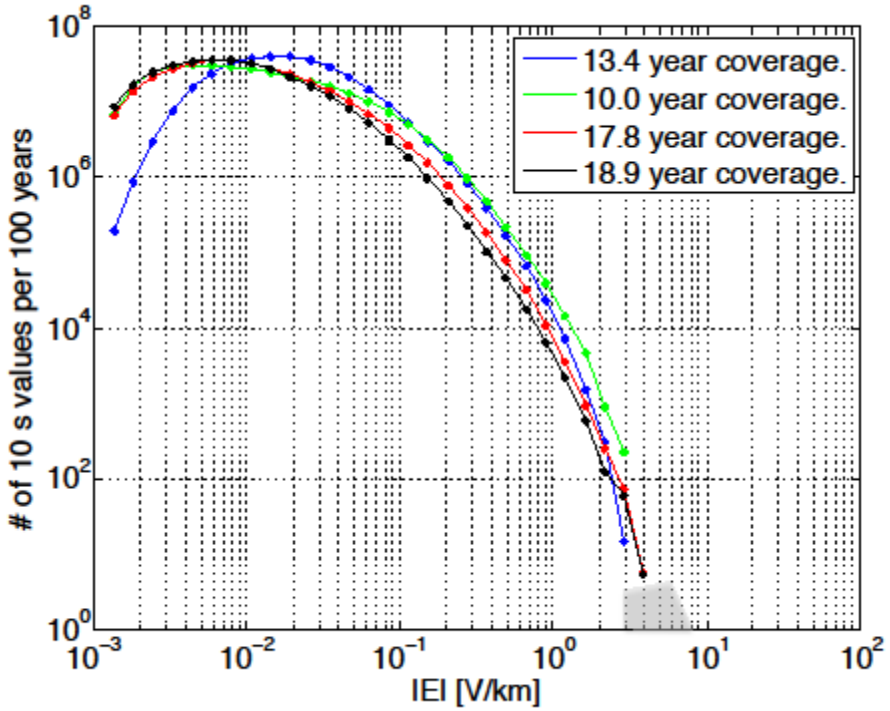


Figure I-2: Statistical Occurrence of Spatially Averaged Geoelectric Field Amplitudes.
Four curves with dots correspond to different station groups and the gray area shows a visual extrapolation to 1-in-100 year amplitudes. The legend shows the data coverage for each station group used in computing the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

Extreme Value Analysis

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

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

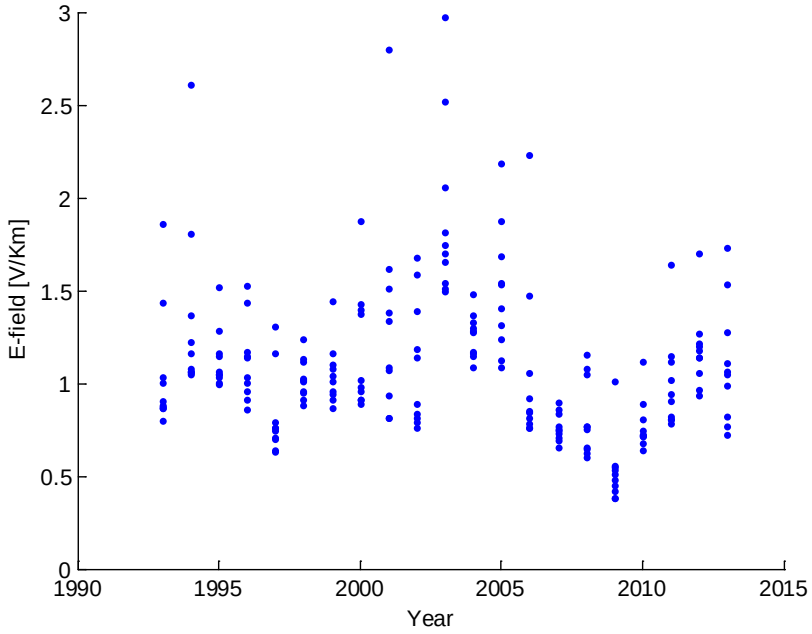


Figure I-3: Scatter Plot of Ten Largest Geoelectric Fields per Year

Data source: IMAGE magnetometer chain from 1993-2013

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

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

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

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

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

Table I-1: Extreme Value Analysis

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

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

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

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

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

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

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

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

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

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

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

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

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

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

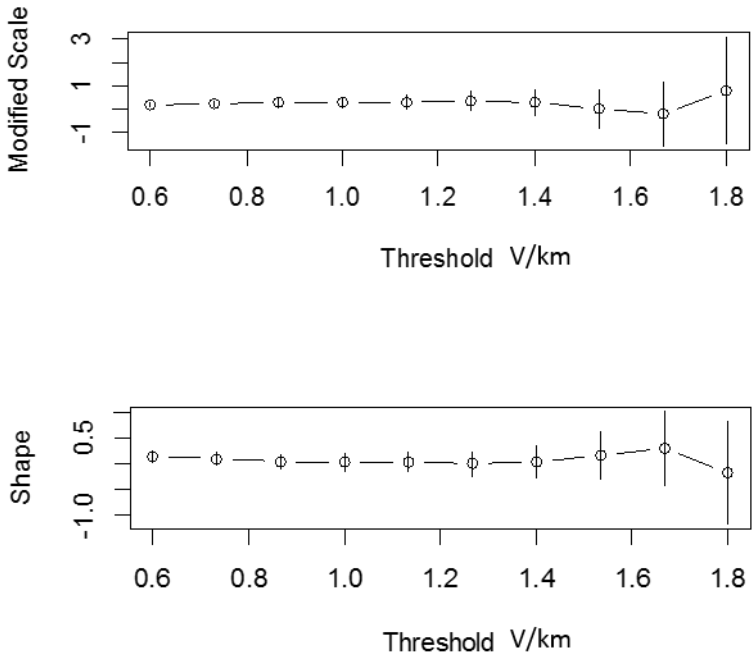


Figure I-4: Parameter Estimates Against Threshold for Statistical Model (3)

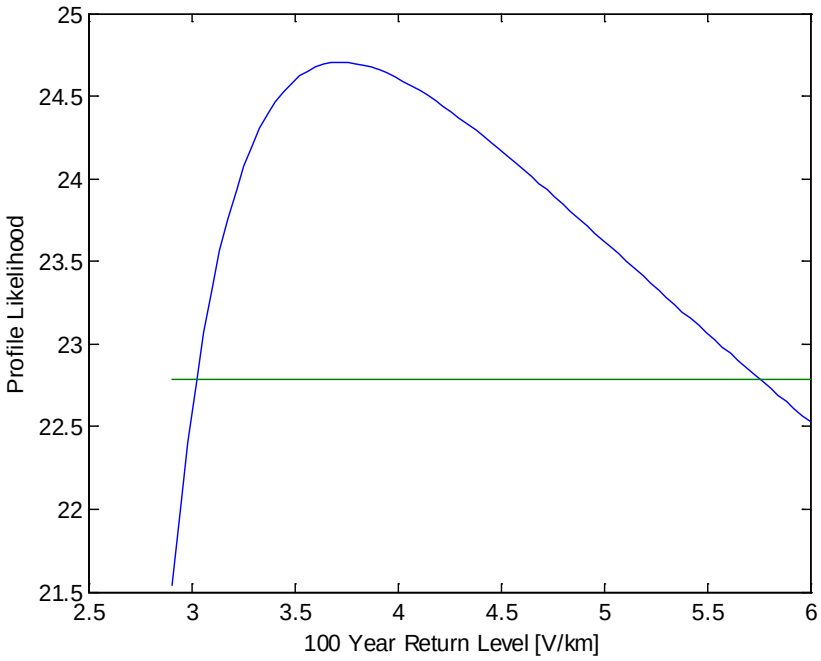


Figure I-5: Profile Likelihood for 100-year Return Level for Statistical Model (4)

Impact of Local Geomagnetic Disturbances on GIC

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

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

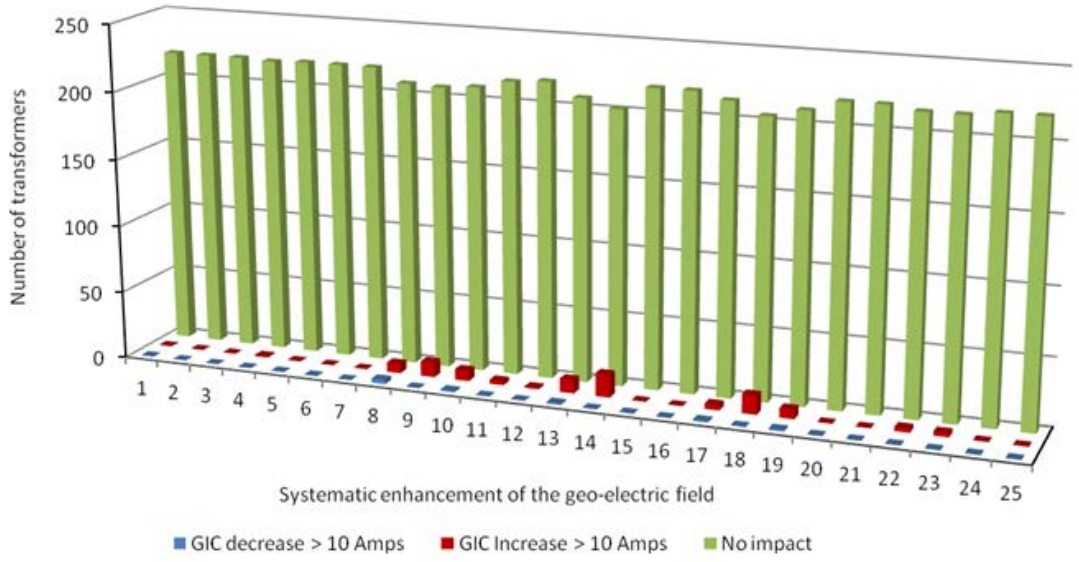


Figure I-6: Number of Transformers that see a 10 A/phase Change in GIC due to Local Geoelectric Field Intensification

Impact of Waveshape on Transformer Hot-spot Heating

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

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

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

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

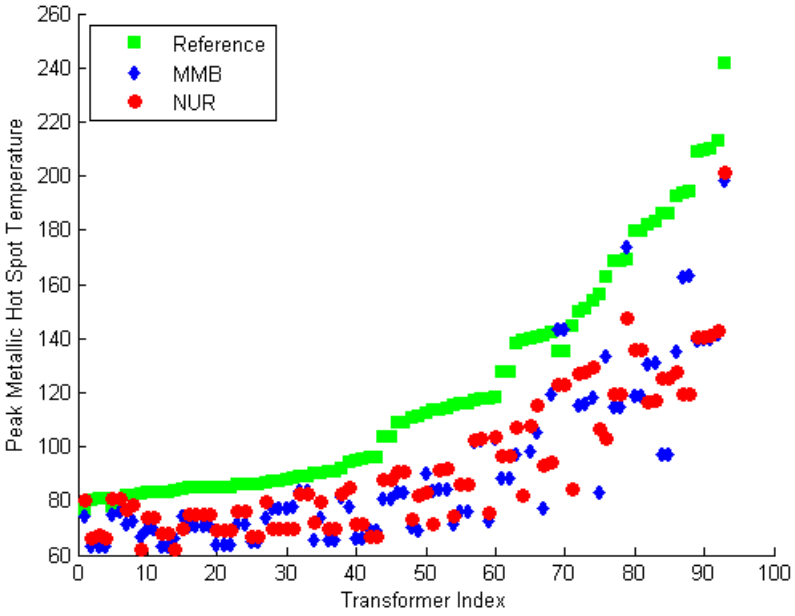


Figure I-7: Calculated Peak Metallic Hot Spot Temperature for All Transformers in a Test System with a Temperature Increase of More Than 20°C for Different GMD Events Scaled to the Same Peak Geoelectric Field

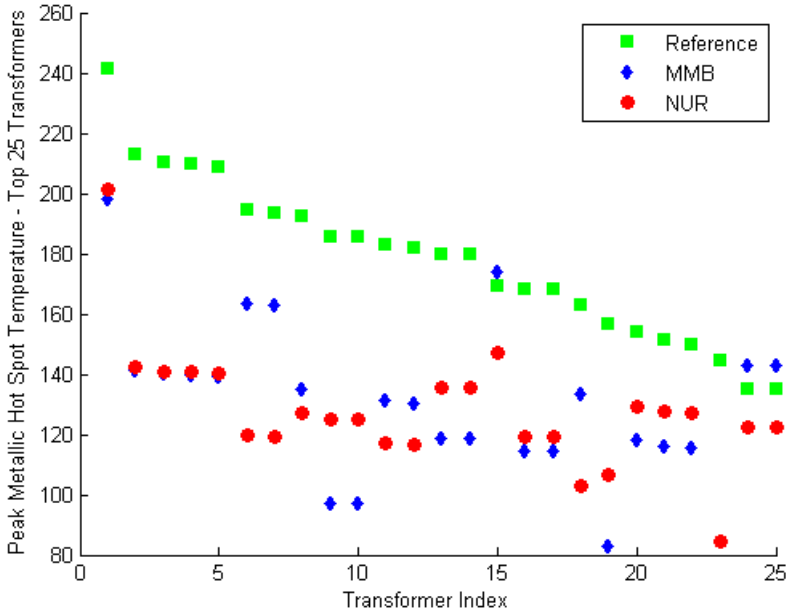


Figure I-8: Calculated Peak Metallic Hot Spot Temperature for the Top 25 Transformers in a Test System for Different GMD Events Scaled to the Same Peak Geoelectric Field

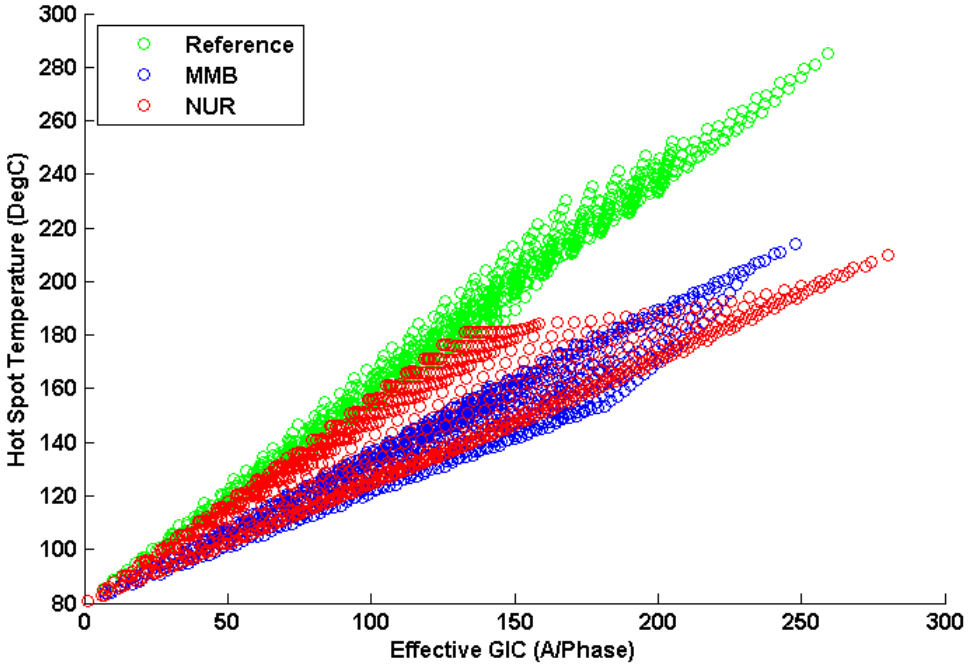


Figure I-9: Calculated Peak Metallic Hot Spot Temperature for all possible circuit orientations and effective GIC.

Appendix II – Scaling the Benchmark GMD Event

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

Scaling the Geomagnetic Field

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

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

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

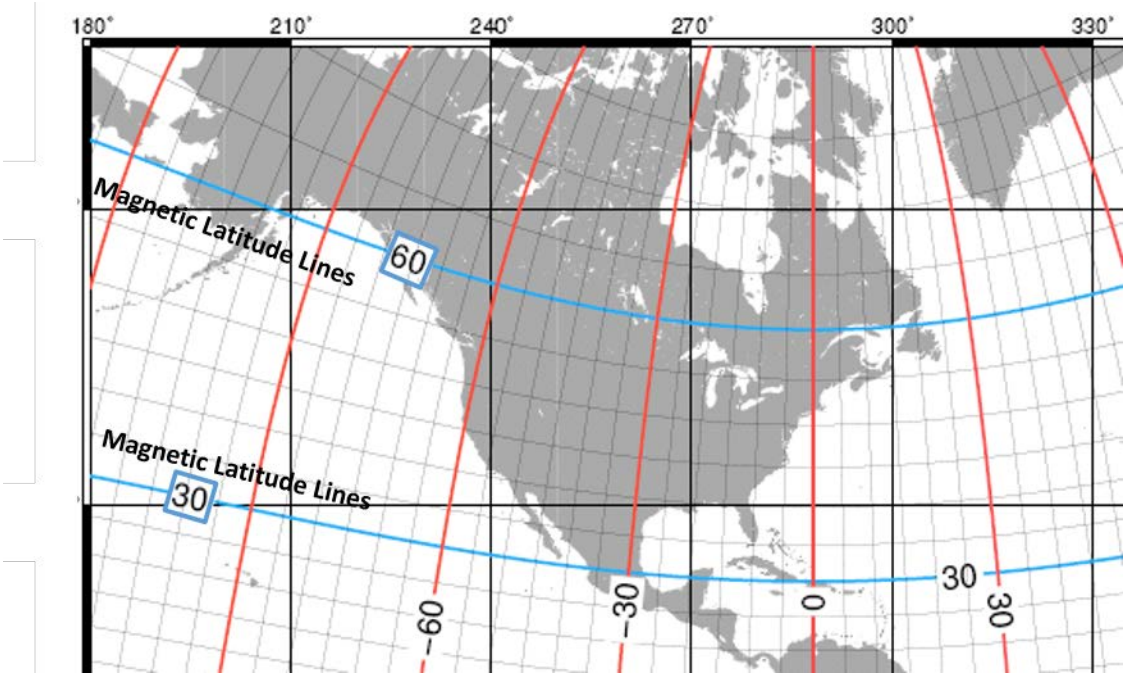


Figure II-1: Geomagnetic Latitude Lines in North America

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

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

Table II-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

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

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

where,

* denotes convolution in the time domain,

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

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

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

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

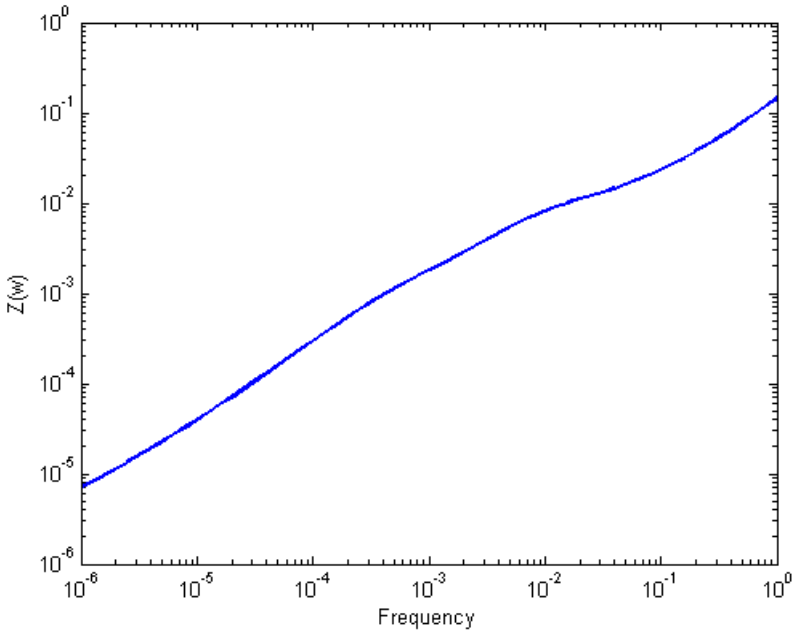


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

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

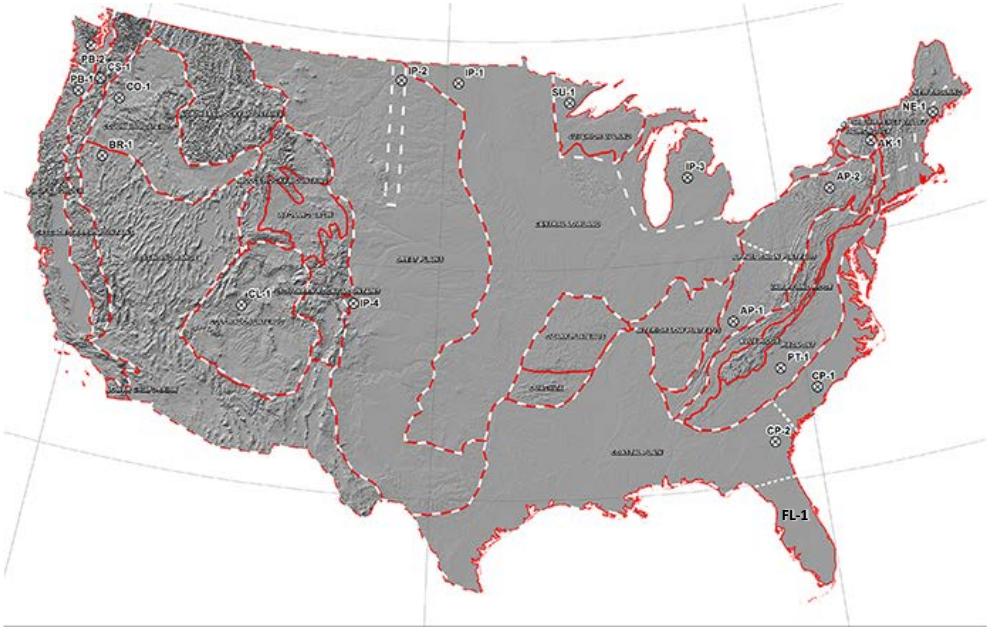
$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)} \quad \text{(II.3)}$$

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

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

- When a ground conductivity model is not available the planning entity should use the largest β factor of adjacent physiographic regions or a technically-justified value.

Physiographic Regions of the Continental United States



Physiographic Regions of Canada



Figure II-3: Physiographic Regions of North America

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

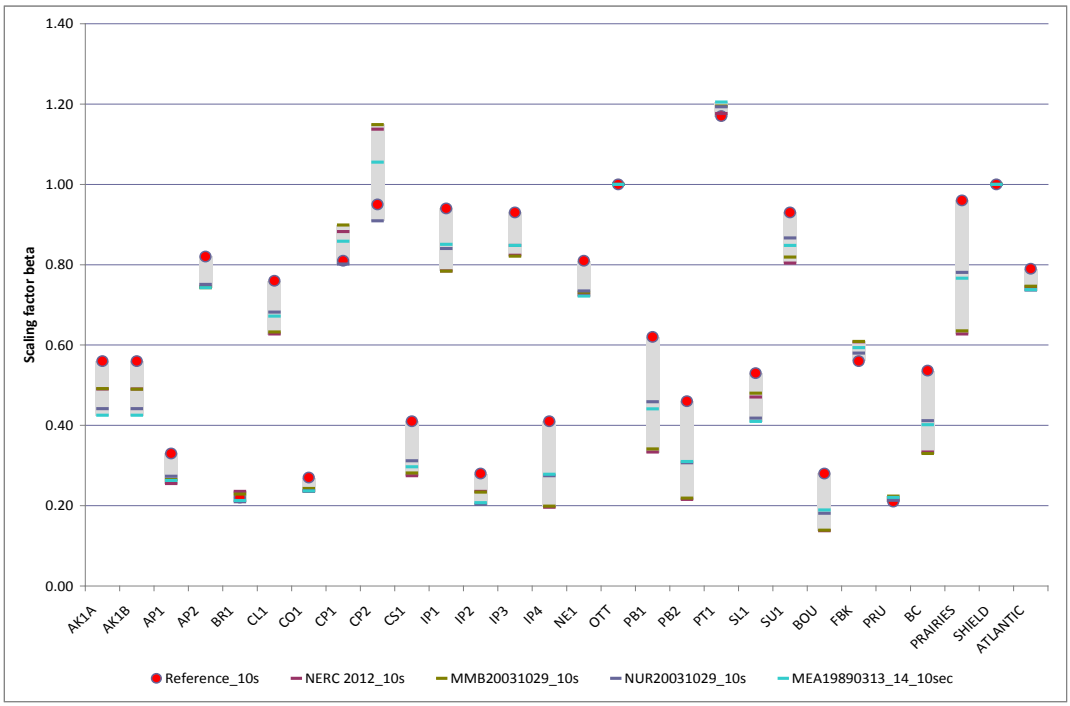


Figure II-4: Beta factors Calculated for Different GMD Events
Red circles correspond to the values in Table II-2

Example Calculations

Example 1

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

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

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

Example 2

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

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

Conductivity factor β=1.17

$$\alpha = 0.56$$

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

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

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

Summary

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

Justification

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

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

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

where

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

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

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

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

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

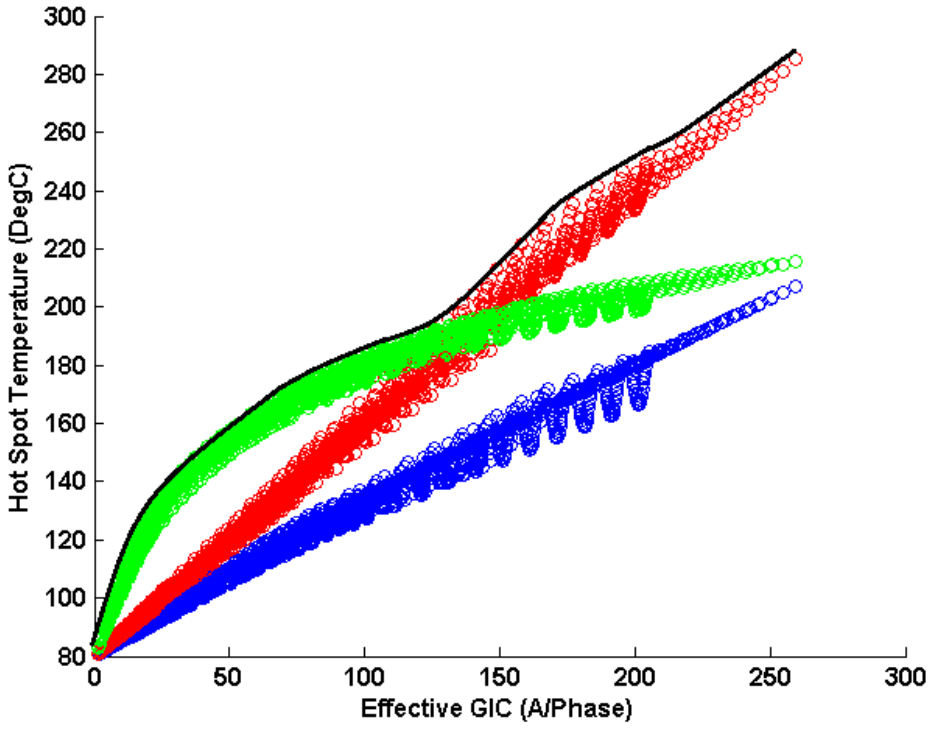


Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: SVC coupling transformer model [2]. Blue: Fingrid model [3]. Green: Autotransformer model [4].

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

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

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

The selection of the 75 A per phase screening threshold is based on the following considerations:

- A thermal assessment using the most conservative thermal models known to date will not result in peak hot spot temperatures above 172°C. Transformer thermal assessments should not be required by Reliability Standards when results will fall well below IEEE Std C57.91-2011 limits.
- Applicable entities may choose to carry out a thermal assessment when the effective GIC is below 75 A per phase to take into account the age or condition of specific transformers where IEEE Std C57.91- 2011 limits could be assumed to be lower than 200°C.
- The models used to determine the 75 A per phase screening threshold are known to be conservative at higher values of effective GIC, especially the SVC coupling transformer model in [2].
- Thermal models in peer-reviewed technical literature, especially those calculated models without experimental validation, are less conservative than the models used to determine the screening threshold. Therefore, a technically-justified thermal assessment for effective GIC below 75 A per phase using the benchmark GMD event geomagnetic field waveshape will always result in a "pass" on the basis of the state of the knowledge at this point in time.
- Based on simulations, the 75 A per phase screening threshold will result in a maximum instantaneous peak hot spot temperature of 172°C. However, IEEE Std C57.91- 2011 limits assume short term emergency operation (typically 30 minutes). As illustrated in **Figure 2**, simulations of the 75 A per phase screening threshold result in 30-minute duration hot spot temperatures of about

155°C. The threshold provides an added measure of conservatism in not taking into account the duration of hot spot temperatures.

- The models used in the determination of the threshold are conservative but technically justified.
- Winding hot spots are not the limiting factor in terms of hot spots due to half-cycle saturation, therefore the screening criterion is focused on metallic part hot spots only.

The 75 A per phase screening threshold was determined using single-phase transformers, but is applicable to all types of transformer construction. While it is known that some transformer types such as three-limb, three-phase transformers are intrinsically less susceptible to GIC, it is not known by how much, on the basis of experimentally-supported models.

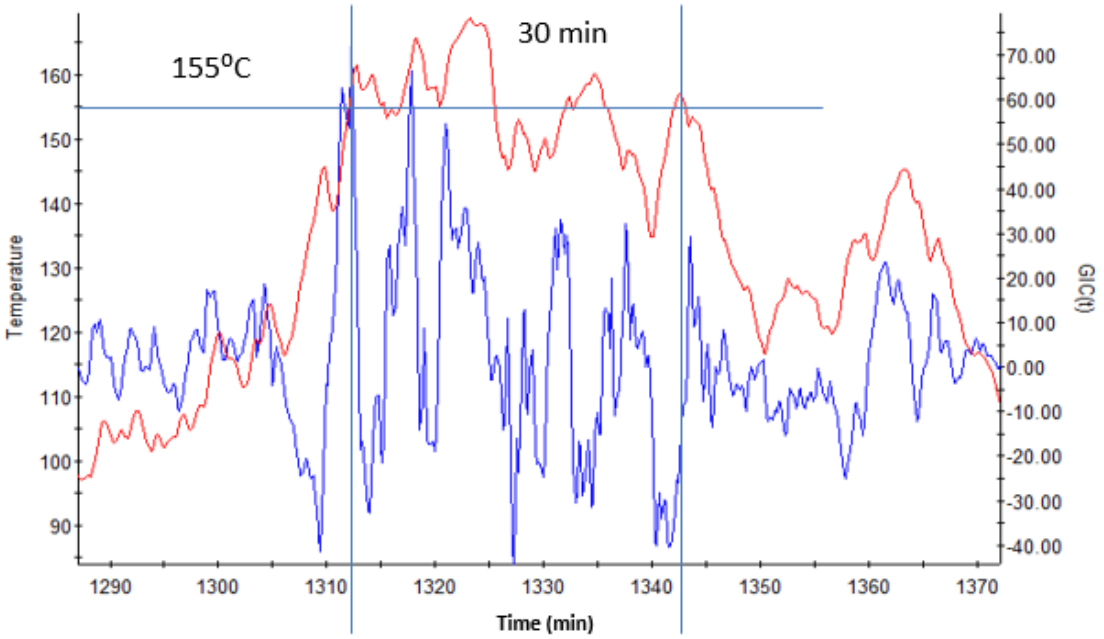


Figure 2: Metallic hot spot temperatures calculated using the benchmark GMD event. Red: metallic hot spot temperature. Blue: GIC(t) that produces the maximum hot spot temperature with peak GIC(t) scaled to 75 A/phase.

Appendix

The envelope used for thermal screening (Figure 1) is derived from two thermal models. The first is based on laboratory measurements carried out on 500/16.5 kV 400 MVA single-phase Static Var Compensator (SVC) coupling transformer [2]. Temperature measurements were carried out at relatively small values of GIC (see **Figure 3**). The asymptotic thermal response for this model is the linear extrapolation of the known measurement values. Although the near-linear behavior of the asymptotic thermal response is consistent with the measurements made on a Fingrid 400 kV 400 MVA five-leg core-type fully-wound transformer [3] (see **Figures 4 and 5**), the extrapolation from low values of GIC is very conservative, but reasonable for screening purposes.

The second transformer model is based on a combination of measurements and modeling for a 400 kV 400 MVA single-phase core-type autotransformer [4] (see **Figures 6 and 7**). The asymptotic thermal behavior of this transformer shows a "down-turn" at high values of GIC as the tie plate increasingly saturates but relatively high temperatures for lower values of GIC. The hot spot temperatures are higher than for the two other models for GIC less than 125 A per phase.

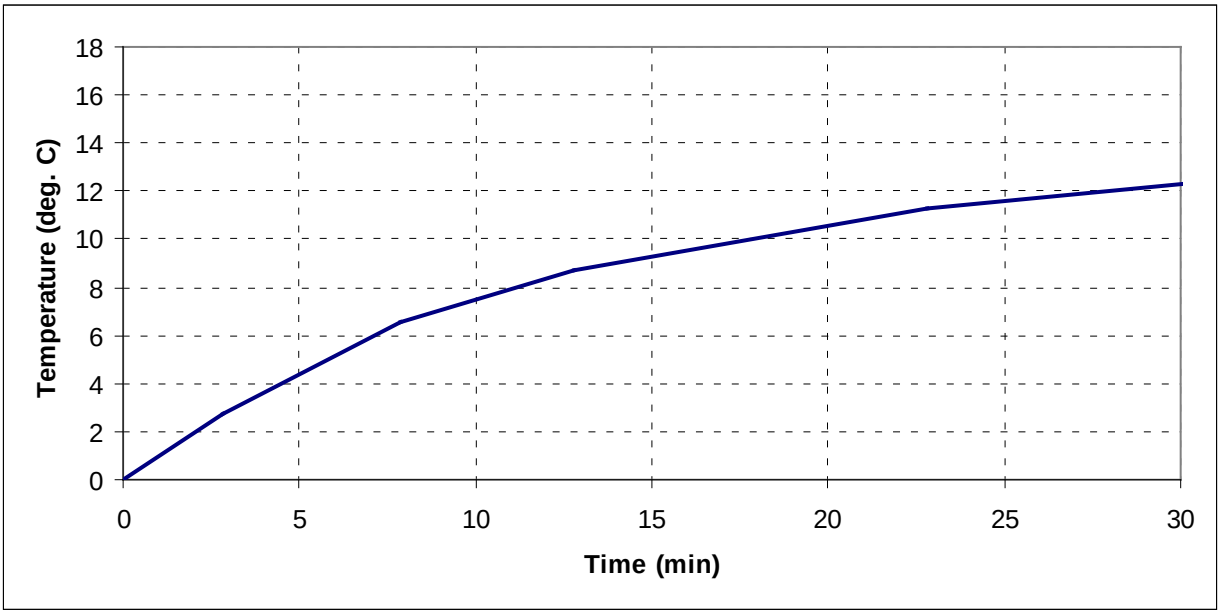


Figure 3: Thermal step response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer to a 5 A per phase dc step.

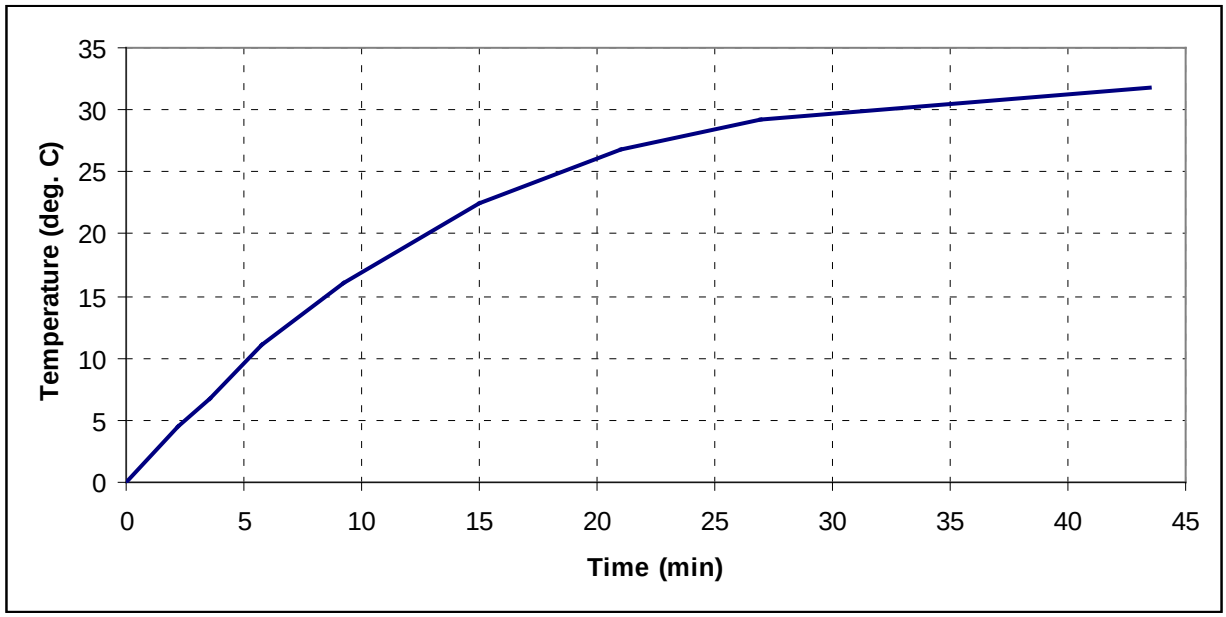


Figure 4: Step thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer to a 16.67 A per phase dc step.

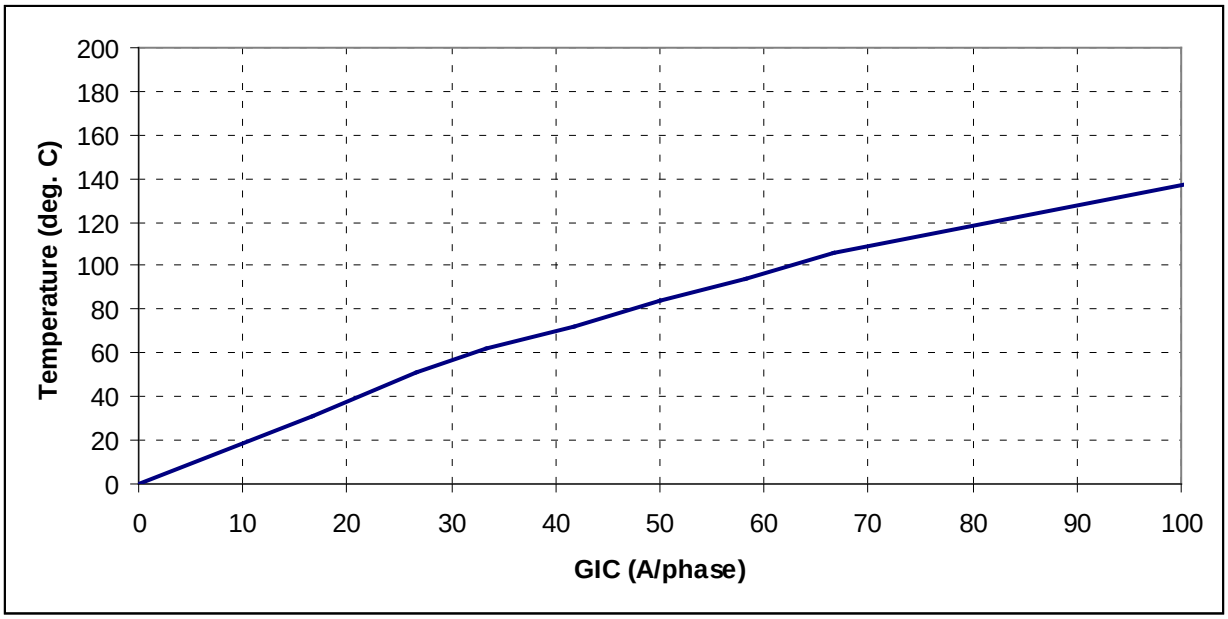


Figure 5: Asymptotic thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer.

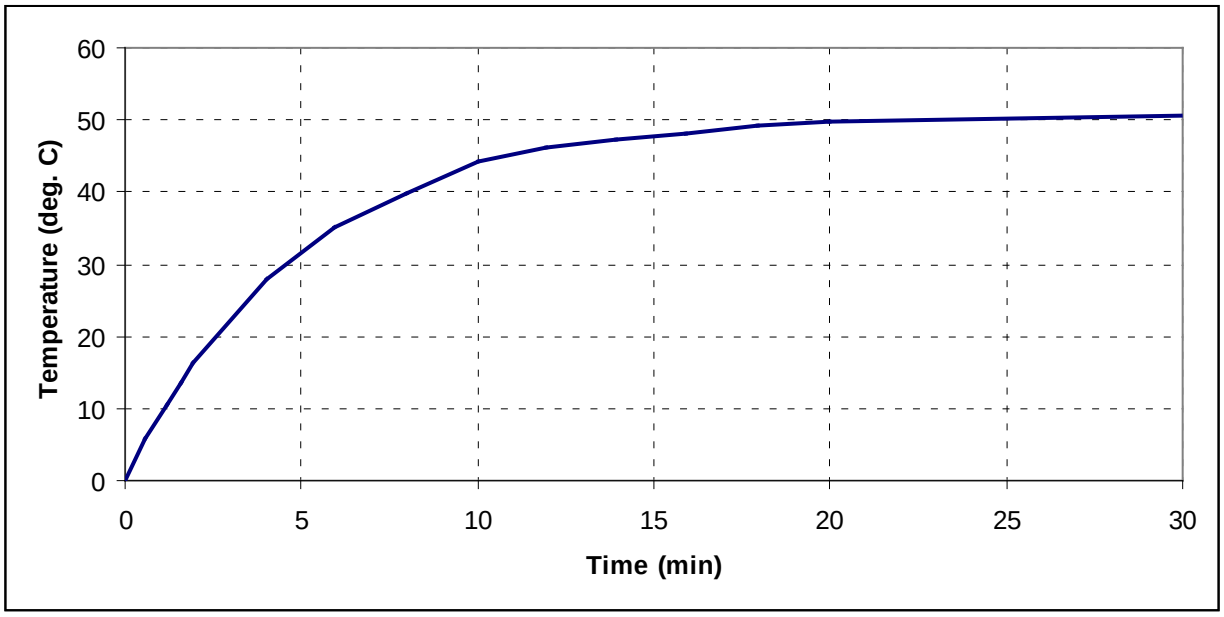


Figure 6: Step thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer to a 10 A per phase dc step.

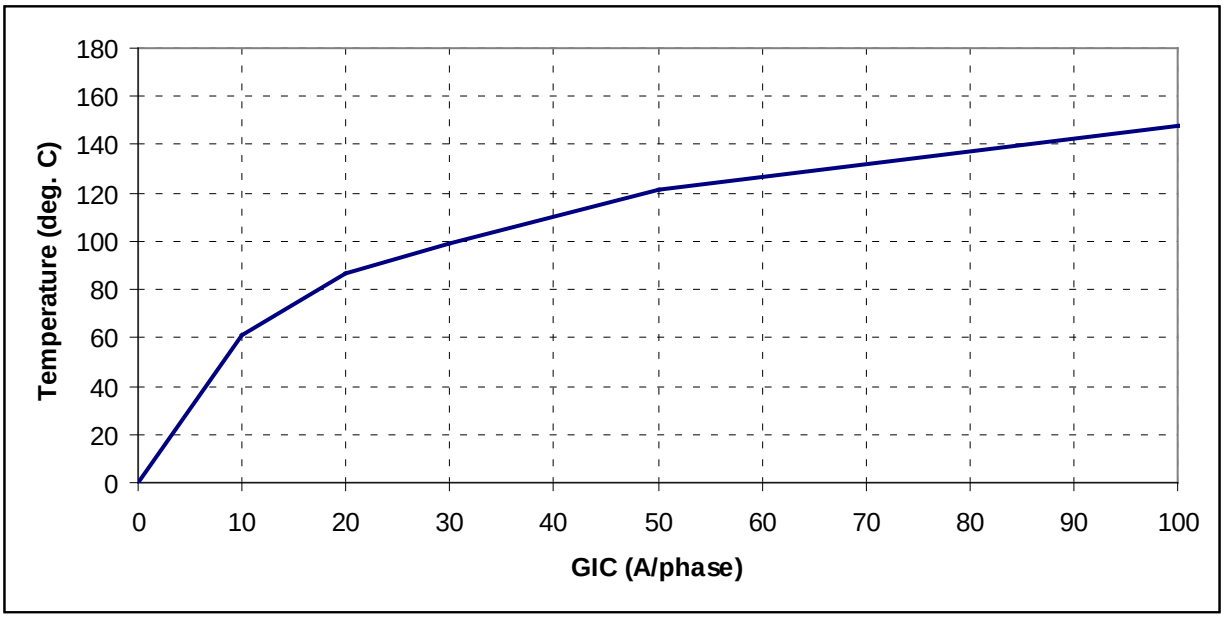


Figure 7: Asymptotic thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer.

The envelope in **Figure 1** can be used as a conservative thermal assessment for effective GIC values of 75 A per phase and greater (see Table 2).

Table 2: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	100	182
10	107	110	186
20	128	120	190
30	139	130	193
40	148	140	204
50	157	150	213
60	169	160	221
70	170	170	230
75	172	180	234
80	175	190	241
90	179	200	247

For instance, if effective GIC is 130 A per phase and oil temperature is assumed to be 80°C, peak hot spot temperature is 193°C. This value is below the 200°C IEEE Std C57.91-2011 threshold for short time emergency loading and this transformer will have passed the thermal assessment. If the full heat run oil temperature is 67°C at maximum ambient temperature, then 150 A per phase of effective GIC translates into a peak hot spot temperature of 200°C and the transformer will have passed. If the limit is lowered to 180°C to account for the condition of the transformer, then this would be an indication to "sharpen the pencil" and perform a detailed assessment. Some methods are described in Reference [1].

The temperature envelope in Figure 1 corresponds to the values of effective GIC that result in the highest temperature for the benchmark GMD event. Different values of effective GIC could result in lower temperatures using the same model. For instance, the difference in upper and lower bounds of peak temperatures for the SVC coupling transformer model for 150 A per phase is approximately 30°C. In this case, GIC(t) should be generated to calculate the peak temperatures for the actual configuration of the transformer within the system as described in Reference [1]. Alternatively, a more precise thermal assessment could be carried out with a thermal model that more closely represents the thermal behavior of the transformer under consideration.

References

[1] Transformer Thermal Impact Assessment white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[2] Marti, L., Rezaei-Zare, A., Narang, A., "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents," *IEEE Transactions on Power Delivery,* vol.28, no.1, pp.320-327, Jan. 2013.

[3] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

[4] J. Raith, S. Ausserhofer: "GIC Strength verification of Power Transformers in a High Voltage Laboratory", GIC Workshop, Cape Town, April 2014

[5] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transformer Thermal Impact Assessment White Paper

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events

Background

On May 16, 2013, FERC issued Order No. 779, directing NERC to develop Standards that address risks to reliability caused by geomagnetic disturbances (GMDs) in two stages:

- Stage 1 Standard(s) that require applicable entities to develop and implement Operating Procedures. EOP-010-1 – Geomagnetic Disturbance Operations was approved by FERC in June 2014.
- Stage 2 Standard(s) that require applicable entities to conduct assessments of the potential impact of benchmark GMD events on their systems. If the assessments identify potential impacts, the Standard(s) will require the applicable entity to develop and implement a plan to mitigate the risk.

TPL-007-1 is a new Reliability Standard to specifically address the Stage 2 directives in Order No. 779.

Large power transformers connected to the EHV transmission system can experience both winding and structural hot spot heating as a result of GMD events. TPL-007-1 will require owners of such transformers to conduct thermal analyses of their transformers to determine if the transformers will be able to withstand the thermal transient effects associated with the Benchmark GMD event. This paper discusses methods that can be employed to conduct such analyses, including example calculations.

The primary impact of GMDs on large power transformers is a result of the quasi-dc current that flows through wye-grounded transformer windings. This geomagnetically-induced current (GIC) results in an offset of the ac sinusoidal flux resulting in asymmetric or half-cycle saturation (see **Figure 1**).

Half-cycle saturation results in a number of known effects:

- Hot spot heating of transformer windings due to harmonics and stray flux;
- Hot spot heating of non-current carrying transformer metallic members due to stray flux;
- Harmonics;
- Increase in reactive power absorption; and
- Increase in vibration and noise level.

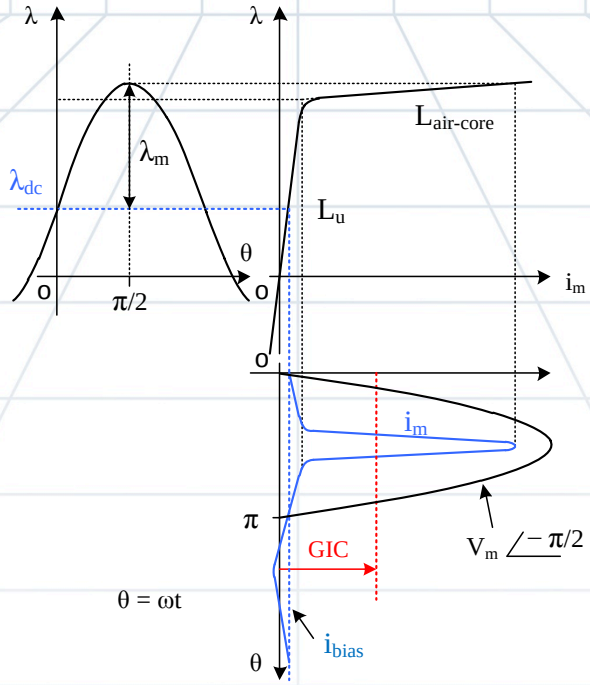


Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

This paper focuses on hot spot heating of transformer windings and non current-carrying metallic parts. Effects such as the generation of harmonics, increase in reactive power absorption, vibration, and noise are not within the scope of this document.

Technical Considerations

The effects of half-cycle saturation on HV and EHV transformers, namely localized "hot spot" heating, are relatively well understood, but are difficult to quantify. A transformer GMD impact assessment must consider GIC amplitude, duration, and transformer physical characteristics such as design and condition (e.g., age, gas content, and moisture in the oil). A single threshold value of GIC cannot be justified as a "pass or fail" screening criterion where "fail" means that the transformer will suffer damage. A single threshold value of GIC only makes sense in the context where "fail" means that a more detailed study is required and that "pass" means that GIC in a particular transformer is so low that a detailed study is unnecessary. Such a threshold would have to be technically justifiable and sufficiently low to be considered a conservative value within the scope of the benchmark.

The following considerations should be taken into account when assessing the thermal susceptibility of a transformer to half-cycle saturation:

- In the absence of manufacturer specific information, use the temperature limits for safe transformer operation such as those suggested in the IEEE Std C57.91-2011 standard [1] for hot spot heating during short-term emergency operation. This standard does not suggest that exceeding these limits will result in transformer failure, but rather that it will result in additional aging of cellulose in the paper-oil insulation and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of evaluating

possible transformer damage due to increased hot spot heating, these thresholds can be considered conservative for a transformer in good operational condition.

- The worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).
- Bulk oil temperature due to ambient temperature and transformer loading must be added to the incremental temperature rise caused by hot spot heating. For planning purposes, maximum ambient and loading temperature should be used unless there is a technically justified reason to do otherwise.
- The time series or "waveshape" of the reference GMD event in terms of peak amplitude, duration, and frequency of the geoelectric field has an important effect on hot spot heating. Winding and metallic part hot spot heating have different thermal time constants, and their temperature rise will be different if the GIC currents are sustained for 2, 10, or 30 minutes for a given GIC peak amplitude.
- The "effective" GIC in autotransformers (reflecting the different GIC ampere-turns in the common and the series windings) must be used in the assessment. The effective current $I_{dc,eq}$ in an autotransformer is defined by [2].

$$I_{dc,eq} = I_H + (I_N/3 - I_H)V_X/V_H \quad (1)$$

where

I_H is the dc current in the high voltage winding;
I_N is the neutral dc current;
V_H is the rms rated voltage at HV terminals;
V_X is the rms rated voltage at the LV terminals.

Transformer Thermal Impact Assessment Process

A simplified thermal assessment may be based on Table 2 from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This table, shown as Table 1 below, provides the peak metallic hot spot temperatures that can be reached using conservative thermal models. To use Table 1, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after allowing for possible de-rating due to transformer condition. If the effective GIC results in higher than threshold temperatures, then the use of a detailed thermal assessment as described below should be carried out.

Table 1: Upper Bound of Peak Metallic Hot Spot Temperatures Calculated Using the Benchmark GMD Event

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	100	182
10	107	110	186
20	128	120	190
30	139	130	193
40	148	140	204
50	157	150	213
60	169	160	221
70	170	170	230
75	172	180	234
80	175	190	241
90	179	200	247

Two different ways to carry out a detailed thermal impact assessment are discussed below. In addition, other approaches and models approved by international standard-setting organizations such as the Institute of Electrical and Electronic Engineers (IEEE)[1] or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments. All thermal assessment methods should be demonstrably equivalent to assessments that use the benchmark GMD event.

1. Transformer manufacturer GIC capability curves. These curves relate permissible peak GIC (obtained by the user from a steady-state GIC calculation) and loading, for a specific transformer. An example of manufacturer capability curves is provided in **Figure 2**. Presentation details vary between manufacturers, and limited information is available regarding the assumptions used to generate these curves, in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the waveshape of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. In the case of the transformer capability curve shown in **Figure 2** [3], a square pulse of 900 A/phase with a duration of 2 minutes would cause the Flitch plate hot spot to reach a temperature of 180 °C at full load. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC waveshape is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in

[1] For instance, IEEE Std C57.163-2015 Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances

the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

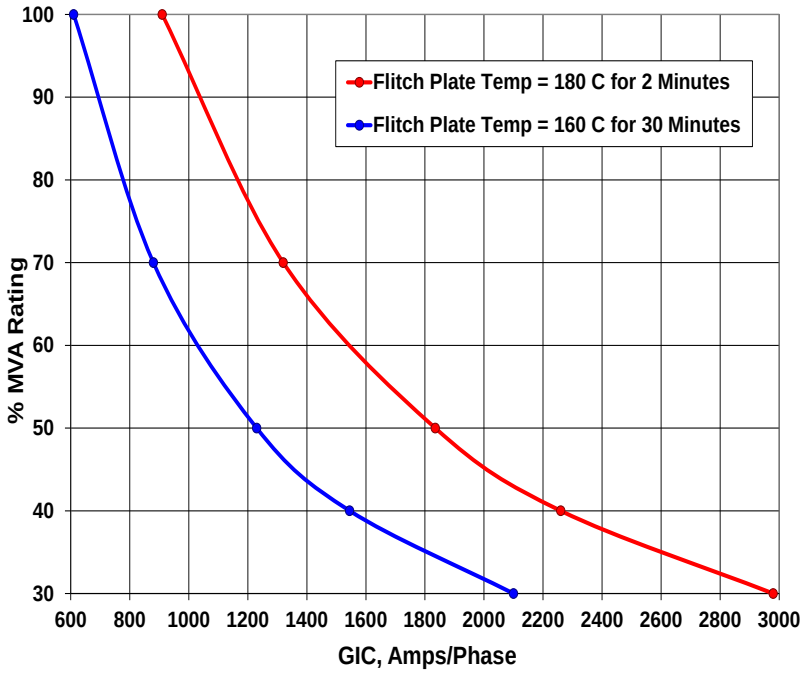


Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [3]

2. Thermal response simulation[2]. The input to this type of simulation is the time series or waveshape of effective GIC flowing through a transformer (taking into account the actual configuration of the system), and the result of the simulation is the hot spot temperature (winding or metallic part) time sequence for a given transformer. An example of GIC input and hotspot temperature time series values from [4] are shown in **Figure 3**. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers. Conservative default values can be used (e.g. those provided in [4]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[2] Technical details of this methodology can be found in [4].

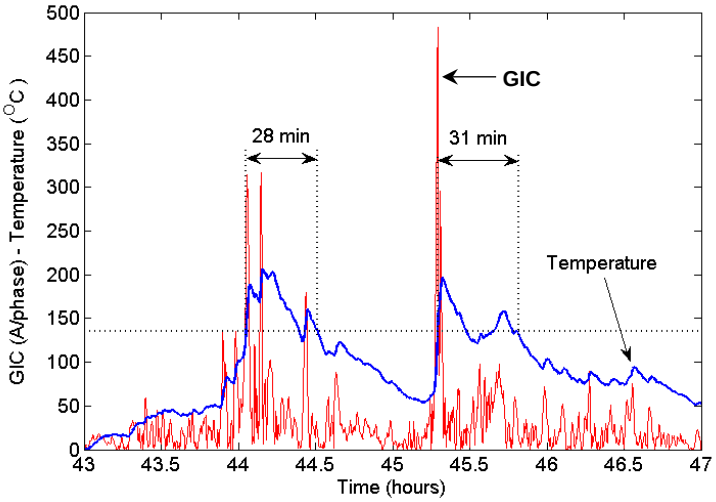


Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [4]

It is important to reiterate that the characteristics of the time sequence or "waveshape" are very important in the assessment of the thermal impact of GIC on transformers. Transformer hot spot heating is not instantaneous. The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes; therefore, hot spot temperatures are heavily dependent on GIC history and rise time, amplitude and duration of GIC in the transformer windings, bulk oil temperature due to loading, ambient temperature and cooling mode.

Calculation of the GIC Waveshape for a Transformer

The following procedure can be used to generate time series GIC data, i.e. GIC(t), using a software program capable of computing GIC in the steady-state. The steps are as follows:

1. Calculate contribution of GIC due to eastward and northward geoelectric fields for the transformer under consideration;
2. Scale the GIC contribution according to the reference geoelectric field time series to produce the GIC time series for the transformer under consideration.

Most available GIC–capable software packages can calculate GIC in steady-state in a transformer assuming a uniform eastward geoelectric field of 1 V/km (GIC_E) while the northward geoelectric field is zero. Similarly, GIC_N can be obtained for a uniform northward geoelectric field of 1 V/km while the eastward geoelectric field is zero. GIC_E and GIC_N are the normalized GIC contributions for the transformer under consideration.

If the earth conductivity is assumed to be uniform (or laterally uniform) in the transmission system of interest, then the transformer GIC (in A/phase) for any value of $E_E(t)$ and $E_N(t)$ can be calculated using (2) [2].

$$GIC(t) = |E(t)| \cdot \{GIC_E \sin(\varphi(t)) + GIC_N \cos(\varphi(t))\} \quad (2)$$

where

$$|E(t)| = \sqrt{E_N^2(t) + E_E^2(t)} \quad (3)$$

$$\varphi(t) = \tan^{-1}\left(\frac{E_E(t)}{E_N(t)}\right) \quad (4)$$

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (5)$$

GIC_N is the effective GIC due to a northward geoelectric field of 1 V/km, and GIC_E is the effective GIC due to an eastward geoelectric field of 1 V/km. The units for GIC_N and GIC_E are A/phase/V/km)

The geoelectric field time series $E_N(t)$ and $E_E(t)$ is obtained, for instance, from the reference geomagnetic field time series [5] after the appropriate geomagnetic latitude scaling factor α is applied[3]. The reference geoelectric field time series is calculated using the reference earth model. When using this geoelectric field time series where a different earth model is applicable, it should be scaled with the conductivity scaling factor β[4]. Alternatively, the geoelectric field can be calculated from the reference geomagnetic field time series after the appropriate geomagnetic latitude scaling factor α is applied and the appropriate earth model is used. In such case, the conductivity scaling factor β is not applied because it is already accounted for by the use of the appropriate earth model.

Applying (5) to each point in $E_N(t)$ and $E_E(t)$ results in GIC(t).

GIC(t) Calculation Example

Let us assume that from the steady-state solution, the effective GIC in this transformer is GIC_E = -20 A/phase if E_N=0, E_E=1 V/km and GIC_N = 26 A/phase if E_N=1 V/km, E_E=0. Let us also assume the geomagnetic field time series corresponds to a geomagnetic latitude where α = 1 and that the earth conductivity corresponds to the reference earth model in [5]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \text{ (A/phase)} \quad (6)$$

$$GIC(t) = -E_E(t) \cdot 20 + \cdot E_N(t) \cdot 26 \text{ (A/phase)} \quad (7)$$

The resulting GIC waveshape GIC(t) is shown in **Figures 5 and 6** and can subsequently be used for thermal analysis.

[3] The geomagnetic factor α is described in [2] and is used to scale the geomagnetic field according to geomagnetic latitude. The lower the geomagnetic latitude (closer to the equator), the lower the amplitude of the geomagnetic field.

[4] The conductivity scaling factor β is described in [2], and is used to scale the geoelectric field according to the conductivity of different physiographic regions. Lower conductivity results in higher β scaling factors.

It should be emphasized that even for the same reference event, the GIC(t) waveshape in every transformer will be different, depending on the location within the system and the number and orientation of the circuits connecting to the transformer station. Assuming a single generic GIC(t) waveshape to test all transformers is incorrect.

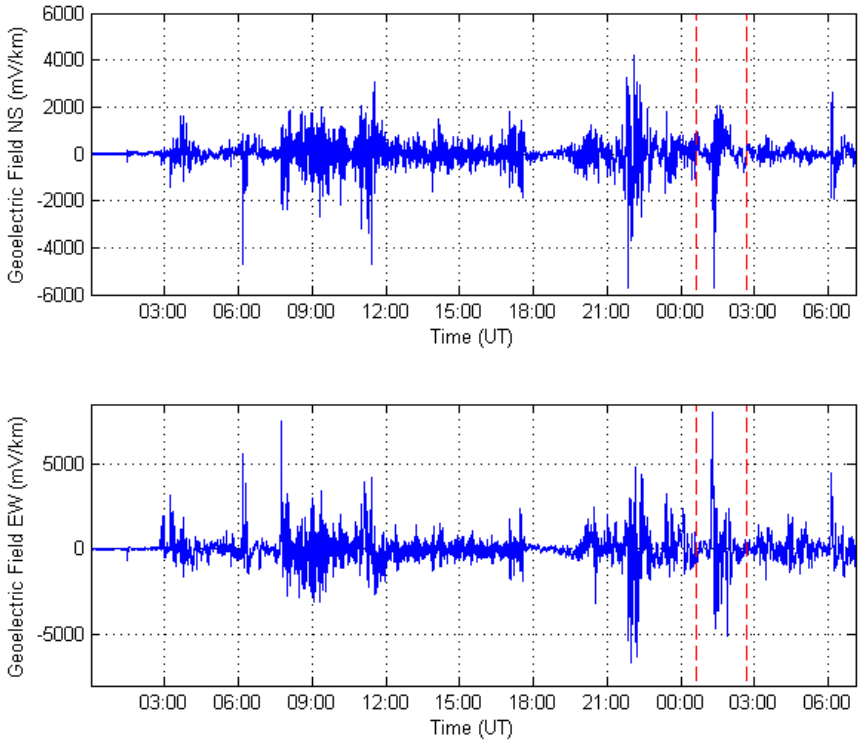


Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model). Zoom area for subsequent graphs is highlighted. Dashed lines approximately show the close-up area for subsequent Figures.

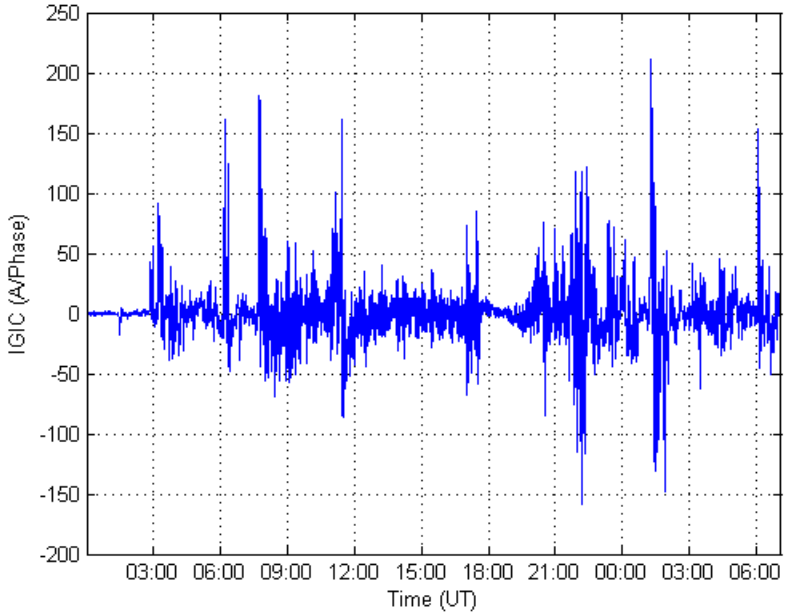


Figure 5: Calculated GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

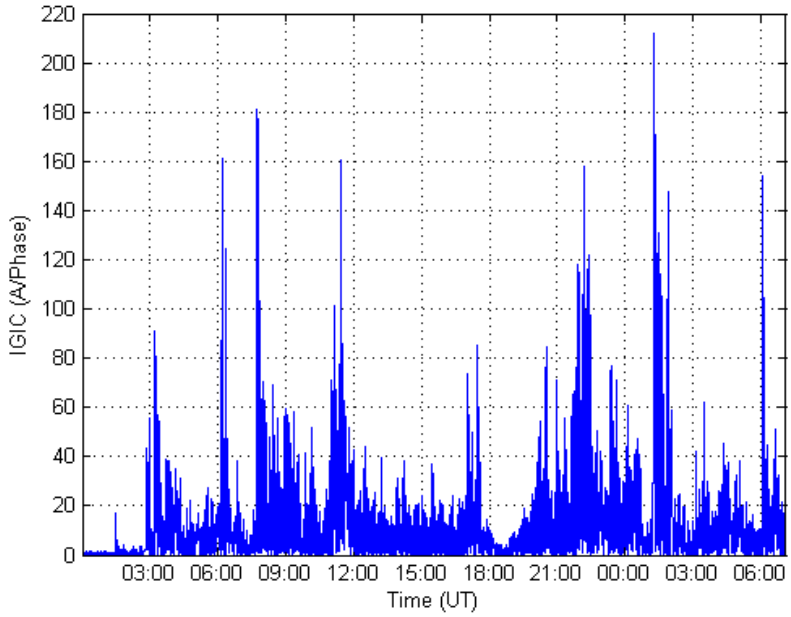


Figure 6: Calculated Magnitude of GIC(t) Assuming α=1 and β=1 (Reference Earth Model)

Transformer Thermal Assessment Examples

There are two basic ways to carry out a transformer thermal analysis once the GIC time series GIC(t) is known for a given transformer: 1) calculating the thermal response as a function of time; and 2) using manufacturer's capability curves.

Example 1: Calculating thermal response as a function of time using a thermal response tool

The thermal step response of the transformer can be obtained for both winding and metallic part hot spots from: 1) measurements; 2) manufacturer's calculations; or 3) generic published values. **Figure 7** shows the measured metallic hot spot thermal response to a dc step of 16.67 A/phase of the top yoke clamp from [6] that will be used in this example. **Figure 8** shows the measured incremental temperature rise (asymptotic response) of the same hot spot to long duration GIC steps.[5]

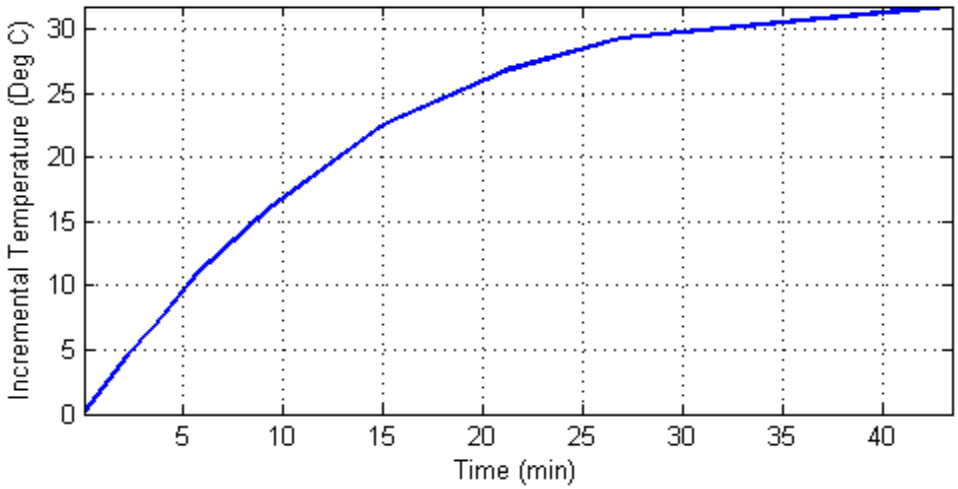


Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step
Metallic hot spot heating.

[5] Heating of bulk oil due to the hot spot temperature increase is not included in the asymptotic response because the time constant of bulk oil heating is at least an order of magnitude larger than the time constants of hot spot heating.

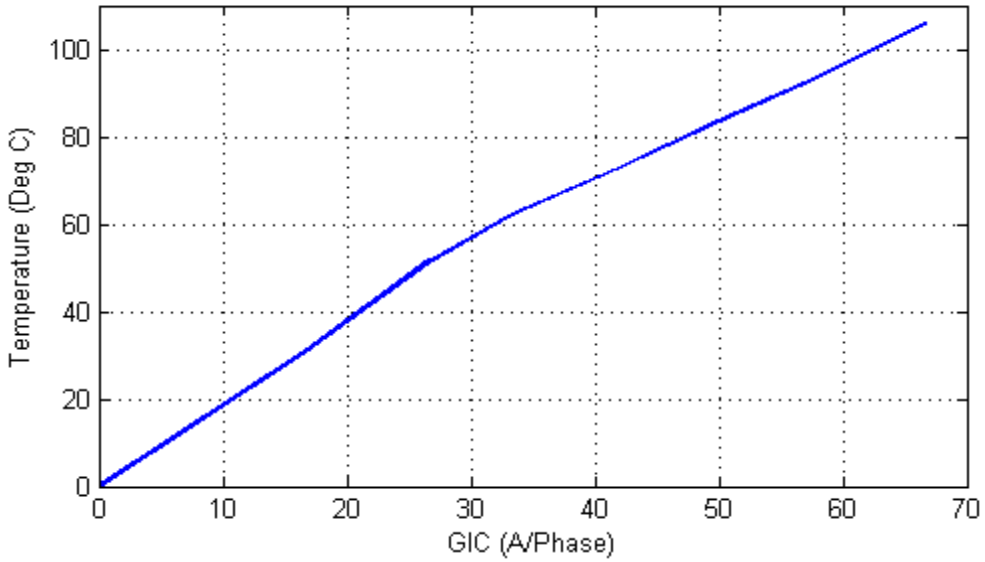


Figure 8: Asymptotic Thermal Step Response
Metallic hot spot heating.

The step response in **Figure 7** was obtained from the first GIC step of the tests carried out in [6]. The asymptotic thermal response in **Figure 8** was obtained from the final or near-final temperature values after each subsequent GIC step. **Figure 9** shows a comparison between measured temperatures and the calculated temperatures using the thermal response model used in the rest of this discussion.

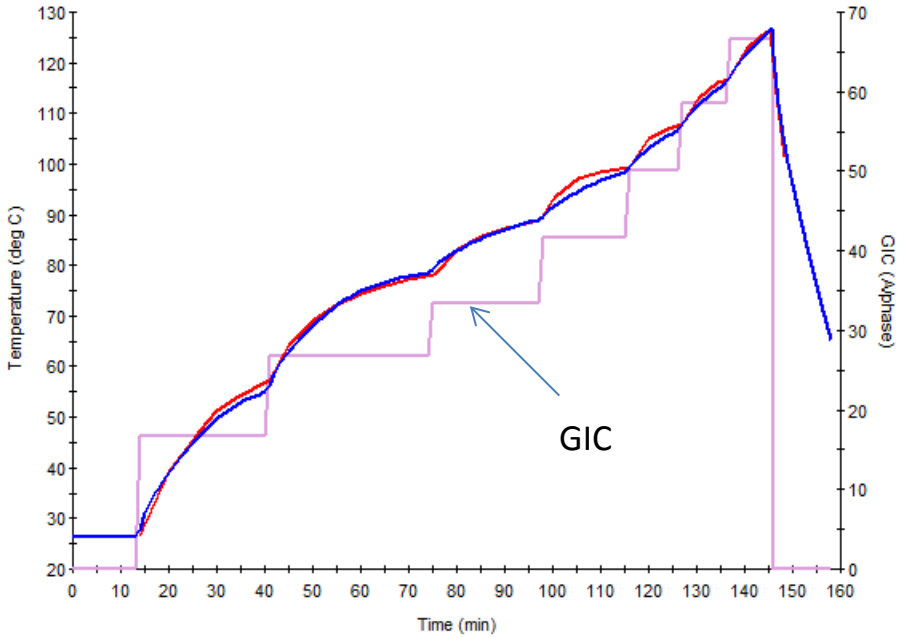


Figure 9: Comparison of measured temperatures (red trace) and simulation results (blue trace). Injected current is represented by the magenta trace.

To obtain the thermal response of the transformer to a GIC waveshape such as the one in **Figure 6**, a thermal response model is required. To create a thermal response model, the measured or manufacturer-calculated transformer thermal step responses (winding and metallic part) for various GIC levels are required. The GIC(t) time series or waveshape is then applied to the thermal model to obtain the incremental temperature rise as a function of time $\theta(t)$ for the GIC(t) waveshape. The total temperature is calculated by adding the oil temperature, for example, at full load.

Figure 10 illustrates the calculated GIC(t) and the corresponding hot spot temperature time series $\theta(t)$. **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

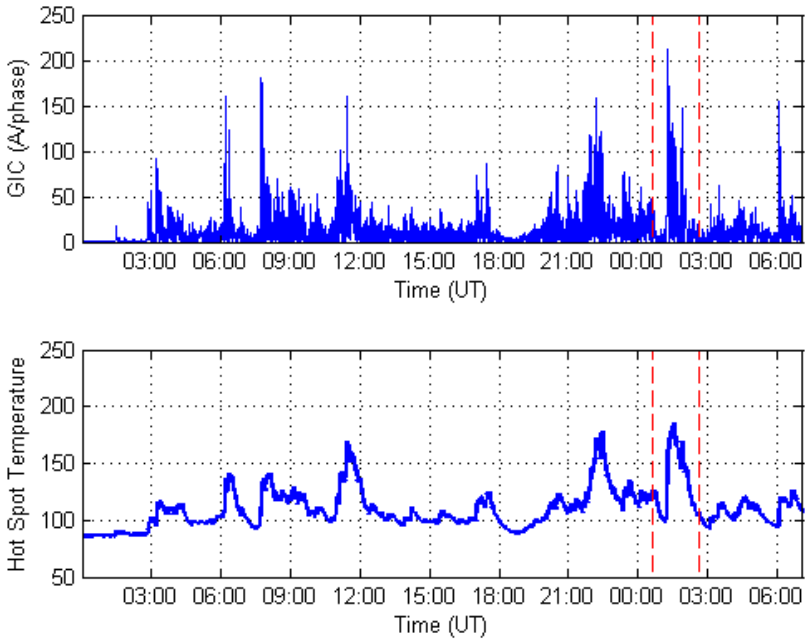


Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature $\theta(t)$ Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

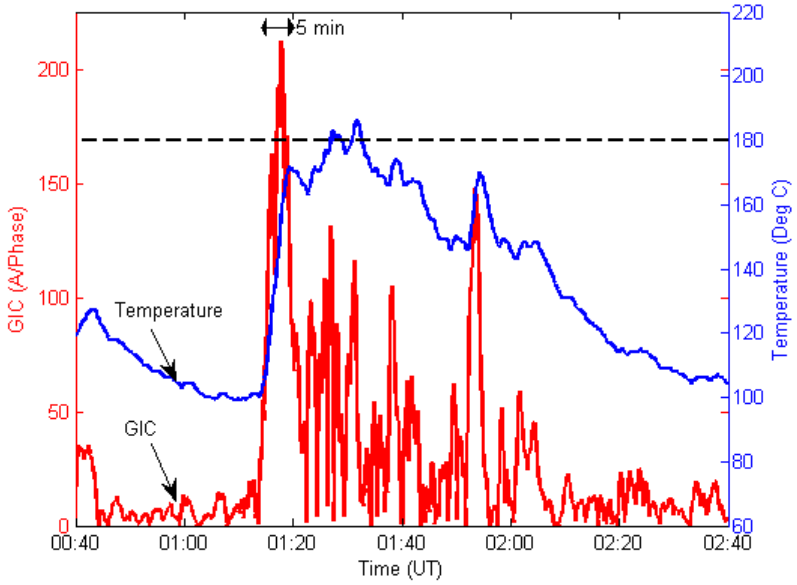


Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91 emergency loading hot spot threshold of 200°C for metallic hot spot heating is not exceeded. Peak temperature is 186°C. The IEEE standard is silent as to whether the temperature can be higher than 200°C for less than 30 minutes. Manufacturers can provide guidance on individual transformer capability.

It is not unusual to use a lower temperature threshold of 180°C to account for calculation and data margins, as well as transformer age and condition. **Figure 11** shows that 180°C will be exceeded for 5 minutes.

At 75% loading, the initial temperature is 64.6 °C rather than 85.3 °C, and the hot spot temperature peak is 165°C, well below the 180°C threshold (see **Figure 12**).

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then the full load limits would be exceeded for approximately 22 minutes.

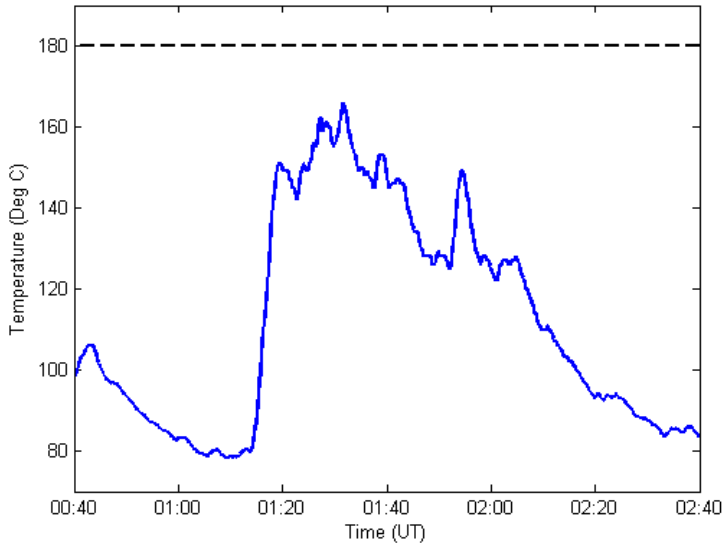


Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

Example 2: Using a Manufacturer's Capability Curves

The capability curves used in this example are shown in **Figure 13**. To maintain consistency with the previous example, these particular capability curves have been reconstructed from the thermal step response shown in **Figures 7** and **8**, and the simplified loading curve shown in **Figure 14** (calculated using formulas from IEEE Std C57.91).

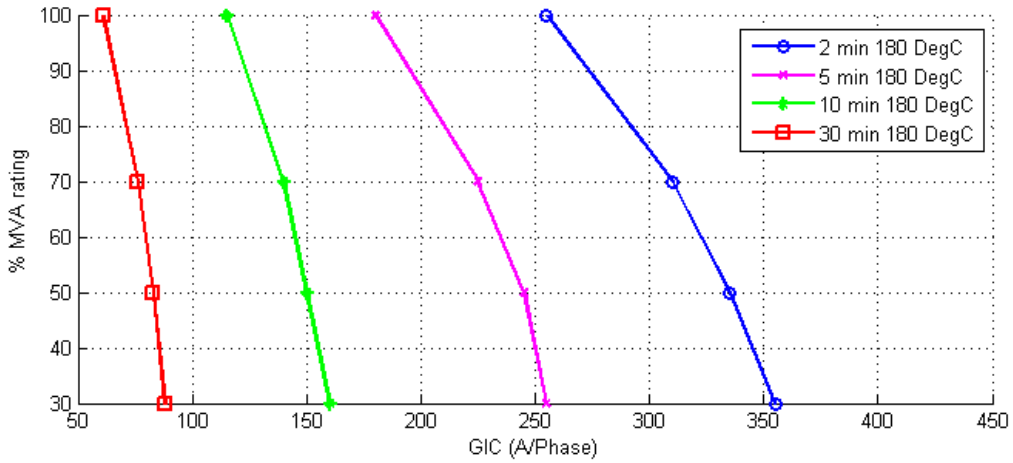


Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

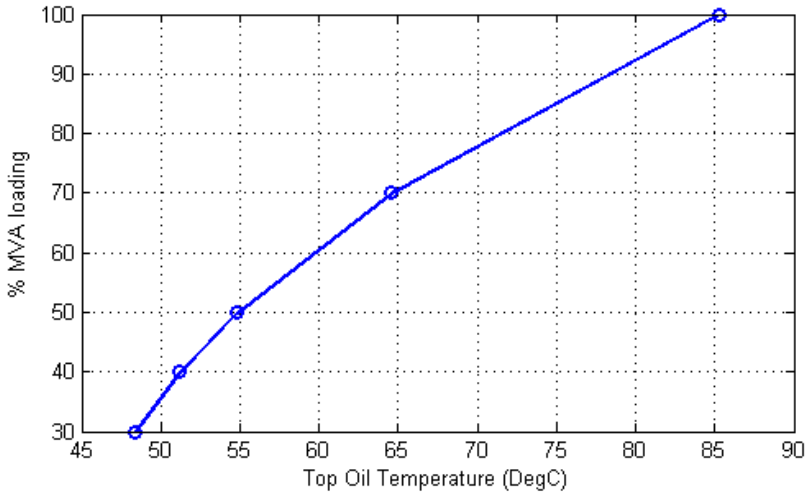


Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

The basic notion behind the use of capability curves is to compare the calculated GIC in a transformer with the limits at different GIC pulse widths. A narrow GIC pulse has a higher limit than a longer duration or wider one. If the calculated GIC and assumed pulse width falls below the appropriate pulse width curve, then the transformer is within its capability.

To use these curves, it is necessary to estimate an equivalent square pulse that matches the waveshape of GIC(t), generally at a GIC(t) peak. **Figure 15** shows a close-up of the GIC near its highest peak superimposed to a 255 Amperes per phase, 2 minute pulse at 100% loading from **Figure 13**. Since a narrow 2-minute pulse is not representative of GIC(t) in this case, a 5 minute pulse with an amplitude of 180 A/phase at 100% loading has been superimposed on **Figure 16**. It should be noted that a 255 A/phase, 2 minute pulse is equivalent to a 180 A/phase 5 minute pulse from the point of view of transformer capability. Deciding what GIC pulse is equivalent to the portion of GIC(t) under consideration is a matter of engineering judgment.

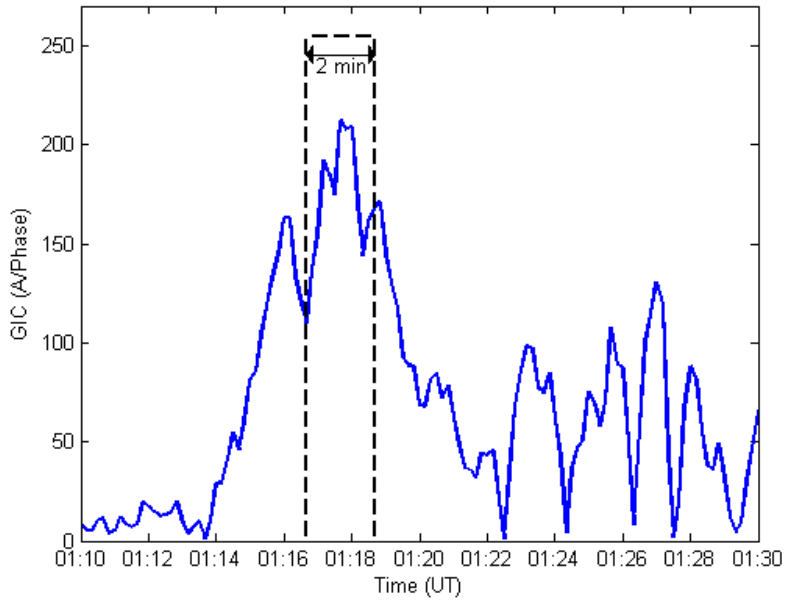


Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

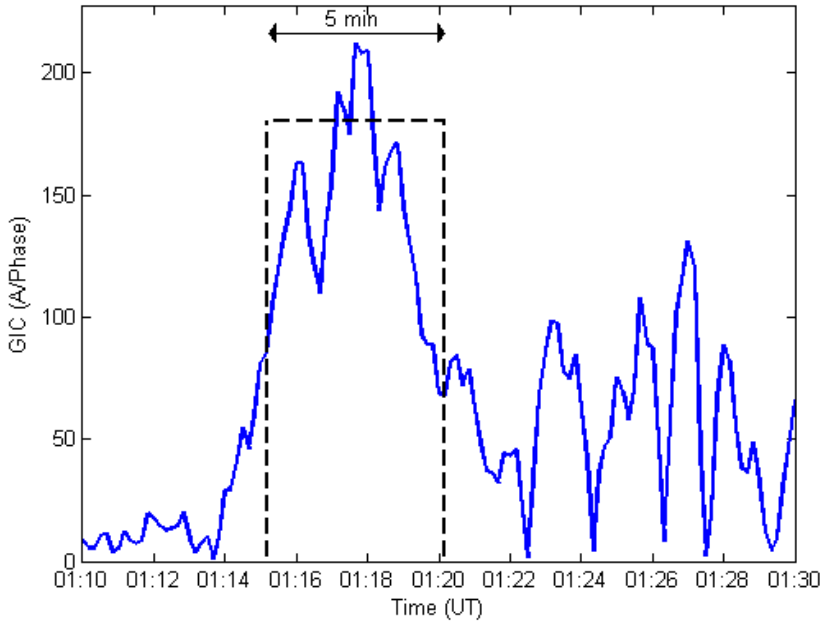


Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

When using a capability curve, it should be understood that the curve is derived assuming that there is no hot spot heating due to prior GIC at the time the GIC pulse occurs (only an initial temperature due to loading). Therefore, in addition to estimating the equivalent pulse that matches GIC(t), prior hot spot heating must be accounted for. From

these considerations, it is unclear whether the capability curves would be exceeded at full load with a 180 °C threshold in this example.

At 70% loading, the two and five minute pulses from **Figure 13** would have amplitudes of 310 and 225 A/phase, respectively. The 5 minute pulse is illustrated in **Figure 17**. In this case, judgment is also required to assess if the GIC(t) is within the capability curve for 70% loading. In general, capability curves are easier to use when GIC(t) is substantially above, or clearly below the GIC thresholds for a given pulse duration.

If a conservative threshold of 160°C were used to account for the age and condition of the transformer, then a new set of capability curves would be required.

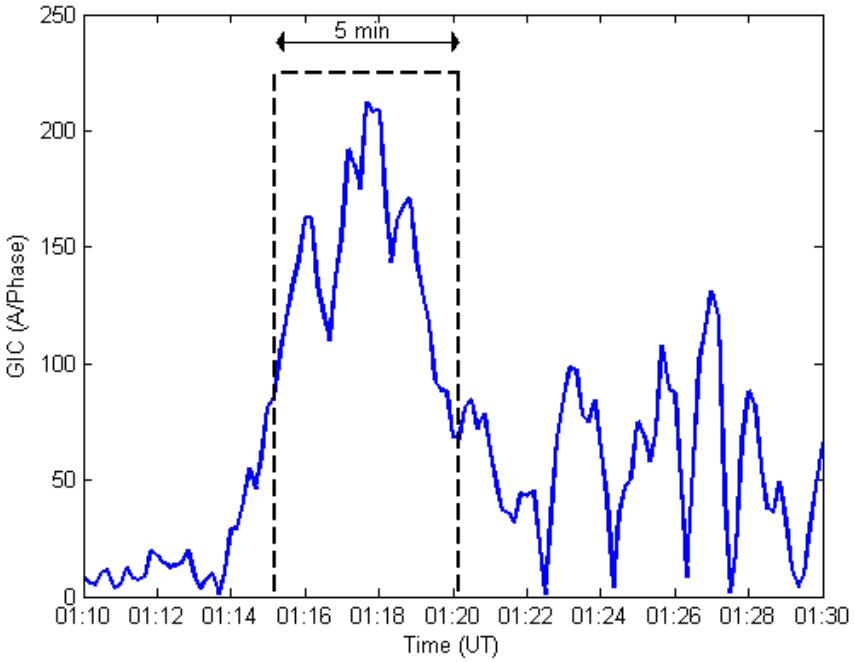


Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

References

[1] "IEEE Guide for loading mineral-oil-immersed transformers and step-voltage regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[2] Application Guide: Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC. Available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

[3] Girgis, R.; Vedante, K. "Methodology for evaluating the impact of GIC and GIC capability of power transformer designs." IEEE PES 2013 General Meeting Proceedings. Vancouver, Canada.

[4] Marti, L., Rezaei-Zare, A., Narang, A. "Simulation of Transformer Hotspot Heating due to Geomagnetically Induced Currents." IEEE Transactions on Power Delivery, vol.28, no.1. pp 320-327. January 2013.

[5] Benchmark Geomagnetic Disturbance Event Description white paper. Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] Lahtinen, Matti. Jarmo Elovaara. "GIC occurrences and GIC test for 400 kV system transformer". IEEE Transactions on Power Delivery, Vol. 17, No. 2. April 2002.

[7] "Screening Criterion for Transformer Thermal Impact Assessment". Developed by the Project 2013-03 (Geomagnetic Disturbance) standard drafting team. Available at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	PRC-025-1 – Generator Relay Loadability		
Date Submitted:	August 25, 2016		
SAR Requester Information for #1			
Name:	Rich Quest		
Organization:	Midwest Reliability Organization		
Telephone:	(651) 855-1704	Email:	rp.quest@midwestreliability.org
SAR Requester Information for #2			
Name:	Jerry Thompson, E.I.T.		
Organization:	Kestrel Power Engineering		
Telephone:	(571) 293-1119	Email:	jerry@kestrelpower.com
SAR Requester Information for #3			
Name:	Joe DePoorter		
Organization:	Madison Gas & Electric		
Telephone:	(608) 252-1599	Email:	JDePoorter@mge.com

Request to propose a new or a revision to a Reliability Standard			
SAR Requester Information for #4			
Name:	Éric Loiselle, ing.		
Organization:	Hydro-Québec TransÉnergie		
Telephone:	(514) 879-4100	Email:	Loiselle.Eric2@hydro.qc.ca
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to Existing Standard		☐ Withdrawal of Existing Standard ☒ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR proposes revising PRC-025-1 for four specific problems. 1. Prevent instances of non-compliance for conditions where the Generator Owner may be prevented from achieving the margin specified by the standard for dispersed generation resources (DGR). 2. Prevent a lowering of reliability and potential non-compliance where the Generator Owner might apply a non-standard relay element application and undermine the goal of the standard. 3. Prevent a lowering of reliability where the Generator Owner might only apply part of the Table 1 application(s) thereby misapplying the loadability margins to relays for the stated application(s). 4. Prevent a lowering of dependability of protective relays directional toward the transmission system at generating facilities that are remote to the transmission network.
Purpose or Goal (How does this request propose to address the problem described above?):
Consider revising the PRC-025-1 standard through the standards development process to: (1) provide alternative loadability Options for Table 1 specific to DGR; (2) address the inclusion or exclusion of the 50 element (i.e., instantaneous), (3) review Table 1 for proper application where there is more than one application for the available Option(s), and (4) provide alternative or additional Options for Table 1 specific to relay applications that are directional toward the transmission system where the interconnecting transmission line impedance may be a factor in determining the maximum reactive output of the generators and associated relay settings.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
This SAR proposes the need for revising PRC-025-1 for four specific problems. 1. PRC-025-1, Table 1 requires setting the overcurrent relay of a Protection System applied to an asynchronous generating unit or an Element utilized in the aggregation of DGR to a margin greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor. This may result in instances of non-compliance due manufacturer requirements or physical limitations of DGR and may result in an overly conservative relay setting. Consider revising the standard to provide alternative options for setting the overcurrent element of a Protection System applied to an asynchronous generating unit and an Element utilized in the aggregation of DGR. 2. There is potential for Generator Owners to apply a pick up setting of the 50 element (i.e., instantaneous overcurrent) of a Protection System, which is not applicable to the standard, that is lower than the minimum pick up established by the standard for the 51 element (i.e., time delayed overcurrent). The 50 element is generally not used in the generator applications where the 51 element is found in the standard. Consider revising the standard to address the inclusion or exclusion of the 50 element for the various overcurrent applications within Table 1. 3. There is potential for Generator Owners not to apply loadability margins to all load-responsive protective relays in Table 1 of PRC-025-1 under the "Application" column that may affect loadability. For example, the Application column from Table 1 (Options 4, 5, and 6): *"Asynchronous generating unit(s) (including inverter-based installations),* ***or*** *Elements utilized in the aggregation of dispersed power producing resources."* The above clause is separated by an "or" conjunction and may lead the Generator Owner to set one particular application and not the other. This may create a gap in achieving the goal of the standard when loadability margins are not applied to relays on certain Elements. Consider revising the standard to make it clear whether either or both of the listed Elements in the Application column of Options 1-6 must meet the criteria of the particular Option. 4. In the case of remote generating facilities that are electrically weak at its connection to the transmission network, the maximum reactive power required by the specific Table 1 Options is too high to be observed in any recoverable stressed condition. This is due to the system impedance (mainly line impedance) restricting the maximum reactive power output by the generator, no matter the generator characteristics. Lastly, applying the existing Table 1 Options for relay applications directional toward the transmission system results in an overly

SAR Information
conservative relay setting and could require reducing the backup protection coverage in order to comply with the stressed system condition anticipated by the standard.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The PRC-025-1 standard became effective on October 1, 2014 and has a phased implementation of five and seven years (i.e., 2019 or 2021) depending on the scope of work required by the Generator Owner. During the early stages of implementation, the above four problems were revealed by industry. The scope of work will be to consider providing (1) an alternative loadability margin for DGR, (2) revision that includes or excludes 50 element for overcurrent applications, (3) clarification of the application of the Elements in Table 1 of PRC-025-1 for each option that has two applicable Elements separated by an "or" conjunction, and (4) alternative or additional Option(s) (e.g., calculation or method) for determining loadability settings for relays that are directional toward the transmission.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
1. Consider revising the PRC-025-1 standard concerning #1 above through the standards development process to provide a means to determine alternative loadability Options for Table 1 of the standard specific to DRG equipment where there could be a manufacturer requirement or physical equipment limitation. Similar to the provisions already contained in the standard, consider methods that would eliminate the potential for non-compliance and/or a violation of manufacturer specifications. For example: (a) a provision could allow a margin consistent with the manufacturer's requirements or based on the limitation of the equipment; (b) a provision to allow the DRG output to be studied through simulation (e.g., similar to Options 1c and 2c) and the relays to be set with an appropriate margin determined through the standard development process; (c) a provision to exempt equipment with fixed limitations installed prior to the effective date of PRC-025-1 or other justifiable date; and/or (d) any other equally effective and efficient method to accomplish the goal. 2. Consider revising the PRC-025-1 standard concerning #2 above to address the inclusion or exclusion of the 50 element (i.e., instantaneous overcurrent) of a Protection System with or without intentional time delay. Newer techniques in generator protection applications may result in a gap due to non-traditional applications of generator overcurrent relays.

SAR Information
3. Consider revising the PRC-025-1 standard concerning #3 above through the standards development process to bring awareness and clarification whether either or both of the Elements listed in the "Application" column of Table 1, Options 1-6 are to have loadability margins applied to the load-responsive protective relays. 4. Consider revising the PRC-025-1 standard concerning #4 above through the standards development process to provide a means to determine alternative loadability Option(s) for Table 1 of the standard specific to relays directional toward the transmission system. Similar to the provisions already contained in the standard, consider: (a) alternative Options for relay settings where the interconnecting transmission line impedance has a significant impact the maximum reactive output of the generating facility and the associated relay settings, (b) the technical validity of the existing options in the presence of significant transmission line impedance between generation and the network, and/or (c) any other equally effective and efficient method to address the problem of significant line impedance effecting how phase protective relays are set not limit generator loadability while maintaining reliable protection of the BES for all fault conditions.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.

Reliability Functions		
☐	Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the end-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.

Reliability and Market Interface Principles	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
None.	

Related SARs	
SAR ID	Explanation
None.	

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION ~~3~~ TBD

Effective: ~~June 26, 2013~~TBD

to ensure the reliability of the bulk power system

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Section 1.0: Introduction

1.1: Authority
This manual is published by the authority of the NERC Board of Trustees. The Board of Trustees, as necessary to maintain NERC's certification as the Electric Reliability Organization ("ERO"), may file the manual with Applicable Governmental Authorities for approval as an ERO document. When approved, the manual is appended to and provides implementation detail in support of the ERO Rules of Procedure Section 300 — Reliability Standards Development.

Capitalized terms not otherwise defined herein, shall have the meaning set forth in the Definitions Used in the Rules of Procedure, Appendix 2 to the Rules of Procedure.

1.2: Scope
The policies and procedures in this manual shall govern the activities of the North American Electric Reliability Corporation ("NERC") related to the development, approval, revision, reaffirmation, and withdrawal of Reliability Standards, Interpretations, Violation Risk Factors ("VRFs"), Violation Severity Levels ("VSLs"), definitions, Variances, and reference documents developed to support standards for the Reliable Operation and planning of the North American Bulk Power Systems.

This manual also addresses the role of the Standards Committee, drafting team and ballot body in the development and approval of Compliance Elements in conjunction with standard development.

1.3: Background
NERC is a nonprofit corporation formed for the purpose of becoming the North American ERO. NERC works with all stakeholder segments of the electric industry, including electricity users, to develop Reliability Standards for the reliability planning and Reliable Operation of the North American Bulk Power Systems. In the United States, the Energy Policy Act of 2005 added Section 215 to the Federal Power Act for the purpose of establishing a framework to make Reliability Standards mandatory for all Bulk Power System owners, operators, and users. Similar authorities are provided by Applicable Governmental Authorities in Canada. NERC was certified as the ERO effective July 2006. *North American Electric Reliability Corp*., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007).

1.4: Essential Attributes of NERC's Reliability Standards Processes
NERC's Reliability Standards development processes provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing a proposed Reliability Standard consistent with the attributes necessary for American National Standards Institute ("ANSI") accreditation. The same attributes, as well as transparency, consensus-building, and timeliness, are also required under the ERO Rules of Procedure Section 304.

- ***Open Participation***
  Participation in NERC's Reliability Standards development balloting and approval processes shall be open to all entities materially affected by NERC's Reliability Standards. There shall be no financial barriers to participation in NERC's Reliability Standards balloting and approval processes. Membership in the Registered Ballot Body shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements.

- ***Balance***
  NERC's Reliability Standards development processes shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization is able to defeat a matter.

  NERC shall use a voting formula that allocates each industry Segment an equal weight in determining the final outcome of any Reliability Standard action. The Reliability Standards development processes shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed Reliability Standard, definition, Variance, and Interpretation.

- ***Coordination and harmonization with other American National Standards activities***
  NERC is committed to resolving any potential conflicts between its Reliability Standards development efforts and existing American National Standards and candidate American National Standards.

- ***Notification of standards development***
  NERC shall publicly distribute a notice to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a Reliability Standard, definition, or Variance; and for each proposed Interpretation. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on NERC's Reliability Standards web page. All notices shall identify a readily available source for further information.

- ***Transparency***
  The process shall be transparent to the public.

- ***Consideration of views and objections***
  Drafting teams shall give prompt consideration to the written views and objections of all participants as set forth herein. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

- ***Consensus Building***
  The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

- ***Consensus vote***
  NERC shall use its voting process to determine if there is sufficient consensus to approve a proposed Reliability Standard, definition, Variance, or Interpretation. NERC shall form a ballot pool for each Reliability Standard action from interested members of its Registered Ballot Body. Approval of any Reliability Standard action requires:

  - A quorum, which is established by at least 75% of the members of the ballot pool submitting a response excluding unreturned ballots; and
  - A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast during all stages of balloting except the final ballot is the sum of affirmative and negative votes with comments, excluding abstentions, non-responses, and negative votes without comments. During the final ballot, the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

- ***Timeliness***
  Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

- ***Metric Policy***
  The International System of units is the preferred units of measurement in NERC Reliability Standard. However, because NERC's Reliability Standards apply in Canada, the United States and portions of Mexico, where applicable, measures are provided in both the metric and English units.

1.5: Ethical Participation

All participants in the NERC Standard development process, including drafting teams, quality reviewers, Standards Committee members and members of the Registered Ballot Body, are obligated to act in an ethical manner in the exercise of all activities conducted pursuant to the terms and conditions of the Standard Processes Manual and the standard development process.

Section 2.0: Elements of a Reliability Standard

2.1: Definition of a Reliability Standard

A Reliability Standard includes a set of Requirements that define specific obligations of owners, operators, and users of the North American Bulk Power Systems. The Requirements shall be material to reliability and measurable. A Reliability Standard is defined as follows:

> "Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk Power System, including without limiting the foregoing, requirements for the operation of existing Bulk Power System Facilities, including cyber security protection, and including the design of planned additions or modifications to such Facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge Bulk Power System Facilities or to construct new transmission capacity or generation capacity. A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority. *See* Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure.

2.2: Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American Bulk Power Systems.[1] Each Reliability Standard shall enable or support one or more of the reliability principles, thereby ensuring that each Reliability Standard serves a purpose in support of reliability of the North American Bulk Power Systems. Each Reliability Standard shall also be consistent with all of the reliability principles, thereby ensuring that no Reliability Standard undermines reliability through an unintended consequence.

2.3: Market Principles

Recognizing that Bulk Power System reliability and electricity markets are inseparable and mutually interdependent, all Reliability Standards shall be consistent with the market interface principles.[2] Consideration of the market interface principles is intended to ensure that Reliability Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

2.4: Types of Reliability Requirements

Generally, each Requirement of a Reliability Standard shall identify what Functional Entities shall do, and under what conditions, to achieve a specific reliability objective. Although Reliability Standards all follow this format, several types of Requirements may exist, each with a different approach to measurement.

- **Performance-based Requirements** define a specific reliability objective or outcome achieved by one or more entities that has a direct, observable effect on the reliability of the Bulk Power System, *i.e.* an effect that can be measured using power system data or trends. In its simplest form, a performance-based requirement has four components: *who,*

[1] The intent of the set of NERC Reliability Standards is to deliver an adequate level of reliability. The latest set of reliability principles and the latest set of characteristics associated with an adequate level of reliability are posted on the Reliability Standards Resources web page.

[2] The latest set of market interface principles is posted on the Reliability Standards Resources web page.

under what conditions (if any), shall perform what action, to achieve what particular result or outcome.

- **Risk-based Requirements** define actions by one or more entities that reduce a stated risk to the reliability of the Bulk Power System and can be measured by evaluating a particular product or outcome resulting from the required actions. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the Bulk Power System.*

- **Capability-based Requirements** define capabilities needed by one or more entities to perform reliability functions and can be measured by demonstrating that the capability exists as required. A capability-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the Bulk Power System.*

The body of reliability Requirements collectively provides a defense-in-depth strategy supporting reliability of the Bulk Power System.

2.5: Elements of a Reliability Standard

A Reliability Standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the Bulk Power System.

The components of a Reliability Standard may include the following:

Title: A brief, descriptive phrase identifying the topic of the Reliability Standard.

Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the Reliability Standards.[3]

Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.

Applicability: Identifies which entities are assigned reliability requirements. The specific Functional Entities and Facilities to which the Reliability Standard applies.

Effective Dates: Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.

Requirement: An explicit statement that identifies the Functional Entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement for which compliance is mandatory.

[3] Reliability Standards shall be numbered in accordance with the NERC Standards Numbering Convention as provide on the Reliability Standards Resources web page.

Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.[4]

- ***Measure:*** Provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.

- ***Violation Risk Factors and Violation Severity Levels:*** Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved reliability standard.[5] Each requirement in each reliability standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC Staff, at the same time as the associated reliability standard, but are not part of the reliability standard. The Board of Trustees is responsible for approving VRFs and VSLs.

  - ***Violation Risk Factors***
    VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria.[6]

  - ***Violation Severity Levels***
    VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.[7]

Version History: The version history is provided for informational purposes and lists information regarding prior versions of Reliability Standards.

Variance: A Requirement (to be applied in the place of the continent-wide Requirement) that is applicable to a specific geographic area or to a specific set of Registered Entities.

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated Reliability Standard. The Compliance Enforcement Authority will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

***Application guidelines*:** Guidelines to support the implementation of the associated Reliability Standard.

***Procedures*:** Procedures to support implementation of the associated Reliability Standard.

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[4] It is the responsibility of the ERO staff to develop compliance tools for each standard; these tools are not part of the standard but are referenced in this manual because the preferred approach to developing these tools is to use a transparent process that leverages the technical and practical expertise of the drafting team and ballot pool..

[5] The *Sanction Guidelines of the North American Electric Reliability Corporation* identifies the factors used to determine a penalty or sanction for violation of reliability standard and is posted on the NERC Web Site.

[6] The latest set of approved VRF Criteria is posted on the Reliability Standards Resources Web Page.

[7] The latest set of approved VSL Criteria is posted on the Reliability Standards Resources Web Page.

The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.

Section 3.0: Reliability Standards Program Organization

3.1: Board of Trustees

The NERC Board of Trustees shall consider for adoption Reliability Standards, definitions, Variances and Interpretations and associated implementation plans that have been processed according to the processes identified in this manual. Once the Board adopts a Reliability Standard, definition, Variance or Interpretation, the Board shall direct NERC Staff to file the document(s) for approval with Applicable Governmental Authorities.

3.2: Registered Ballot Body

The Registered Ballot Body comprises all entities or individuals that qualify for one of the Segments approved by the Board of Trustees[8], and are registered with NERC as potential ballot participants in the voting on Reliability Standards. Each member of the Registered Ballot Body is eligible to join the ballot pool for each Reliability Standard action.

3.3: Ballot Pool

Each Reliability Standard action has its own ballot pool formed of interested members of the Registered Ballot Body. The ballot pool comprises those members of the Registered Ballot Body that respond to a pre-ballot request to participate in that particular Reliability Standard action. The ballot pool votes on each Reliability Standards action. The ballot pool remains in place until all balloting related to that Reliability Standard action has been completed.

3.4: Standards Committee

The Standards Committee serves at the pleasure and direction of the NERC Board of Trustees, and the Board approves the Standards Committee's Charter.[9] Standards Committee members are elected by their respective Segment's stakeholders. The Standards Committee consists of two members of each of the Segments in the Registered Ballot Body.[10] A member of the NERC Reliability Standards Staff shall serve as the non-voting secretary to the Standards Committee.

The Standards Committee is responsible for managing the Reliability Standards processes for development of Reliability Standards, definitions, Variances and Interpretations in accordance with this manual. The responsibilities of the Standards Committee are defined in detail in the Standards Committee's Charter. The Standards Committee is responsible for ensuring that the Reliability Standards, definitions, Variances and Interpretations developed by drafting teams are developed in accordance with the processes in this manual and meet NERC's benchmarks for Reliability Standards as well as criteria for governmental approval.[11]

The Standards Committee has the right to remand work to a drafting team, to reject the work of a drafting team, or to accept the work of a drafting team. The Standards Committee may disband a drafting team if it determines (a) that the drafting team is not producing a standard in a timely manner; (b) the drafting team

[8] The industry Segment qualifications are described in the Development of the Registered Ballot Body and Segment Qualification Guidelines document posted on the Reliability Standards Resources web page and are included in Appendix 3D of the NERC Rules of Procedure.

[9] The Standards Committee Charter is posted on the Reliability Standards Resources web page.

[10] In addition to balanced Segment representation, the Standards Committee shall also have representation that is balanced among countries based on Net Energy for Load ("NEL"). As needed, the Board of Trustees may approve special procedures for the balancing of representation among countries represented within NERC.

[11] The Ten Benchmarks of an Excellent Reliability Standard and FERC's Criteria for Approving Reliability Standards are posted on the Reliability Standards Resources web page.

is not able to produce a standard that will achieve industry consensus; (c) the drafting team has not addressed the scope of the SAR; or (d) the drafting team has failed to fully address a regulatory directive or otherwise provided a responsive or equally efficient and effective alternative. The Standards Committee may direct a drafting team to revise its work to follow the processes in this manual or to meet the criteria for NERC's benchmarks for Reliability Standards, or to meet the criteria for governmental approval; however, the Standards Committee shall not direct a drafting team to change the technical content of a draft Reliability Standard.

The Standards Committee shall meet at regularly scheduled intervals (either in person, or by other means). All Standards Committee meetings are open to all interested parties.

3.5: NERC Reliability Standards Staff

The NERC Reliability Standards Staff, led by the Director of Standards, is responsible for administering NERC's Reliability Standards processes in accordance with this manual. The NERC Reliability Standards Staff provides support to the Standards Committee in managing the Reliability Standards processes and in supporting the work of all drafting teams. The NERC Reliability Standards Staff works to ensure the integrity of the Reliability Standards processes and consistency of quality and completeness of the Reliability Standards. The NERC Reliability Standards Staff facilitates all steps in the development of Reliability Standards, definitions, Variances, Interpretations and associated implementation plans.

The NERC Reliability Standards Staff is responsible for presenting Reliability Standards, definitions, Variances, and Interpretations to the NERC Board of Trustees for adoption. When presenting Reliability Standards-related documents to the NERC Board of Trustees for adoption or approval, the NERC Reliability Standards Staff shall report the results of the associated stakeholder ballot, including identification of unresolved stakeholder objections and an assessment of the document's practicality and enforceability.

3.6: Drafting Teams

The Standards Committee shall appoint industry experts to drafting teams to work with stakeholders in developing and refining Standard Authorization Requests ("SARs"), Reliability Standards, definitions, and Variances. The NERC Reliability Standards Staff shall appoint drafting teams that develop Interpretations. The NERC Reliability Standards Staff shall provide, or solicit from the industry, essential support for each of the drafting teams in the form of technical writers, legal, compliance, and rigorous and highly trained project management and facilitation support personnel.

Each drafting team may consist of a group of technical, legal, and compliance experts that work cooperatively with the support of the NERC Reliability Standards Staff.[12] The technical experts provide the subject matter expertise and guide the development of the technical aspects of the Reliability Standard, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the Reliability Standard. Each drafting team appointed to develop a Reliability Standard is responsible for following the processes identified in this manual as well as procedures developed by the Standards Committee from the inception of the assigned project through the final acceptance of that project by Applicable Governmental Authorities.

Collectively, each drafting team:

- Drafts proposed language for the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.

[12] The detailed responsibilities of drafting teams are outlined in the Drafting Team Guidelines, which is posted on the Reliability Standards Resources web page.

- Develops and refines technical documents that aid in the understanding of Reliability Standards.
- Works collaboratively with NERC Compliance Monitoring and Enforcement Staff to develop Reliability Standard Audit Worksheets ("RSAWs") at the same time Reliability Standards are developed.
- Provides assistance to NERC Staff in the development of Compliance Elements of proposed Reliability Standards.
- Solicits, considers, and responds to comments related to the specific Reliability Standards development project.
- Participates in industry forums to help build consensus on the draft Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.
- Assists in developing the documentation used to obtain governmental approval of the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.

All drafting teams report to the Standards Committee.

3.7: Governmental Authorities

The Federal Energy Regulatory Commission ("FERC") in the United States of America, and where permissible by statute or regulation, the provincial government of each of the eight Canadian Provinces (Manitoba, Nova Scotia, Saskatchewan, Alberta, Ontario, British Columbia, New Brunswick and Quebec) and the National Energy Board of Canada have the authority to approve each new, revised or withdrawn Reliability Standard, definition, Variance, VRF, VSL and Interpretation following adoption or approval by the NERC Board of Trustees.

3.8: Committees, Subcommittees, Working Groups, and Task Forces

NERC's technical committees, subcommittees, working groups, and task forces provide technical research and analysis used to justify the development of new Reliability Standards and provide guidance, when requested by the Standards Committee, in overseeing field tests or collection and analysis of data. The technical committees, subcommittees, working groups, and task forces provide feedback to drafting teams during both informal and formal comment periods.

The Standards Committee may request that a NERC technical committee or other group prepare a Technical document to support development of a proposed Reliability Standard.

The technical committees, subcommittees, working groups, and task forces share their observations regarding the need for new or modified Reliability Standards or Requirements with the NERC Reliability Standards Staff for use in identifying the need for new Reliability Standards projects for the three-year *Reliability Standards Development Plan*.

3.9: Compliance and Certification Committee

The Compliance and Certification Committee is responsible for monitoring NERC's compliance with its Reliability Standards processes and procedures and for monitoring NERC's compliance with the Rules of Procedure regarding the development of new or revised Reliability Standards, definitions, Variances, and Interpretations. The Compliance and Certification Committee may assist in verifying that each proposed Reliability Standard is enforceable as written before the Reliability Standard is posted for formal stakeholder comment and balloting.

3.10: Compliance Monitoring and Enforcement Program

As applicable, the NERC Compliance Monitoring and Enforcement Program Staff manages and enforces compliance with approved Reliability Standards. Compliance Monitoring and Enforcement Staff are responsible for the development of select compliance tools. The drafting team and the Compliance Monitoring and Enforcement Program Staff shall work together during the Reliability Standard development process to ensure an accurate and consistent understanding of the Requirements and their intent, and to ensure that applicable compliance tools accurately reflect that intent. The goal of this collaboration is to ensure that application of the Reliability Standards in the Compliance Monitoring and Enforcement Program by NERC and the Regional Entities is consistent.

The Compliance Monitoring and Enforcement Program is encouraged to share its observations regarding the need for new or modified Requirements with the NERC Reliability Standards Staff for use in identifying the need for new Reliability Standards projects.

3.11: North American Energy Standards Board ("NAESB")

While NERC has responsibility for developing Reliability Standards to support reliability, NAESB has responsibility for developing business practices and coordination between reliability and business practices as needed. NERC and NAESB developed and approved a procedure[13] to guide the development of Reliability Standards and business practices where the reliability and business practice components are intricately entwined within a proposed Reliability Standard.

[13] The NERC NAESB Template Procedure for Joint Standards Development and Coordination is posted on the Reliability Standards Resources web page.

Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard

There are several steps to the development, modification, withdrawal or retirement of a Reliability Standard.[14]

The development of the *Reliability Standards Development Plan* is the appropriate forum for reaching agreement on whether there is a need for a Reliability Standard and the scope of a proposed Reliability Standard. A typical process for a project identified in the *Reliability Standards Development Plan* that involves a revision to an existing Reliability Standard is shown below. Note that most projects do not include a field test.

[14] The process described is also applicable to projects used to propose a new or modified definition or Variance or to propose retirement of a definition or Variance.

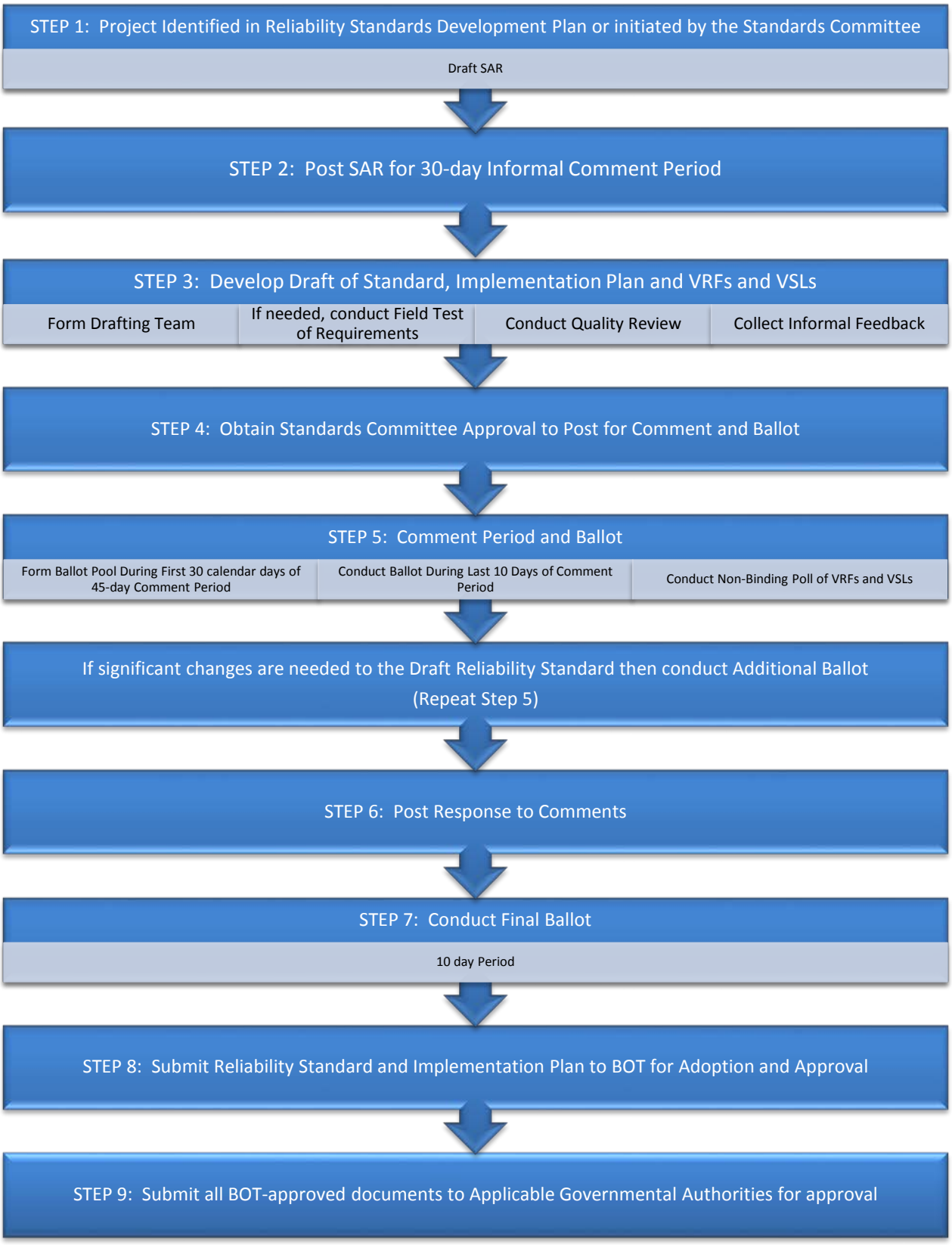


FIGURE 1: Process for Developing or Modifying a Reliability Standard

4.1: Posting and Collecting Information on SARs

Standard Authorization Request

A Standard Authorization Request ("SAR") is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards. Any entity or individual, including NERC committees or subgroups and NERC Staff, may propose the development of a new or modified Reliability Standard, or may propose the retirement of a Reliability Standard (in whole or in part), by submitting a completed SAR[15] to the NERC Reliability Standards Staff. The Standards Committee has the authority to approve the posting of all SARs for projects that propose (i) developing a new or modified Reliability Standard or definition or (ii) propose retirement of an existing Reliability Standard (or elements thereof).

The NERC Reliability Standards Staff sponsors an open solicitation period each year seeking ideas for new Reliability Standards projects (using *Reliability Standards Suggestions and Comments forms*). The open solicitation period is held in conjunction with the annual revision to the *Reliability Standards Development Plan*. While the Standards Committee prefers that ideas for new projects be submitted during this annual solicitation period through submittal of a *Reliability Standards Suggestions and Comments Form*,[16] a SAR proposing a specific project may be submitted to the NERC Reliability Standards Staff at any time.

Each SAR that proposes a "new" or substantially revised Reliability Standard or definition should be accompanied by a technical justification that includes, as a minimum, a discussion of the reliability-related benefits and costs of developing the new Reliability Standard or definition, and a technical foundation document (*e.g.*, research paper) to guide the development of the Reliability Standard or definition. The technical document should address the engineering, planning and operational basis for the proposed Reliability Standard or definition, as well as any alternative approaches considered during SAR development.

The NERC Reliability Standards Staff shall review each SAR and work with the submitter to verify that all required information has been provided. All properly completed SARs shall be submitted to the Standards Committee for action at the next regularly scheduled Standards Committee meeting.

When presented with a SAR, the Standards Committee shall determine if the SAR is sufficiently complete to guide Reliability Standard development and whether the SAR is consistent with this manual. The Standards Committee shall take one of the following actions:

- Accept the SAR.
- Remand the SAR back to the requestor or to NERC Reliability Standards Staff for additional work.
- Reject the SAR. The Standards Committee may reject a SAR for good cause. If the Standards Committee rejects a SAR, it shall provide a written explanation for rejection to the sponsor within ten days of the rejection decision.
- Delay action on the SAR pending one of the following: (i) development of a technical justification for the proposed project; or (ii) consultation with another NERC Committee to determine if there is another approach to addressing the issue raised in the SAR.

If the Standards Committee is presented with a SAR that proposes developing a new Reliability Standard or definition but does not have a technical justification upon which the Reliability Standard or definition can be developed, the Standards Committee shall direct the NERC Reliability Standards Staff to post the

[15] The SAR form can be downloaded from the Reliability Standards Resources web page.
[16] The *Reliability Standards Suggestions and Comments Form* can be downloaded from the Reliability Standards Resources web page.

SAR for a 30-day comment period solely to collect stakeholder feedback on the scope of technical foundation, if any, needed to support the proposed project. If a technical foundation is determined to be necessary, the Standards Committee shall solicit assistance from NERC's technical committees or other industry experts to provide that foundation before authorizing development of the associated Reliability Standard or definition.

During the SAR comment process, the drafting team may become aware of potential regional Variances related to the proposed Reliability Standard. To the extent possible, any regional Variances or exceptions should be made a part of the SAR so that if the SAR is authorized, such variations shall be made a part of the draft new or revised Reliability Standard.

If the Standards Committee accepts a SAR, the project shall be added to the list of approved projects. The Standards Committee shall assign a priority to the project, relative to all other projects under development, and those projects already identified in the *Reliability Standards Development Plan* that are already approved for development.

The Standards Committee shall work with the NERC Reliability Standards Staff to coordinate the posting of SARs for new projects, giving consideration to each project's priority.

4.2: SAR Posting

When the Standards Committee determines it is ready to initiate a new project, the Standards Committee shall direct NERC Staff to post the project's SAR in accordance with the following:

- For SARs that are limited to addressing regulatory directives, or revisions to Reliability Standards that have had some vetting in the industry, authorize posting the SAR for a 30-day informal comment period with no requirement to provide a formal response to the comments received.
- For SARs that address the development of new projects or Reliability Standards, authorize posting the SAR for a 30-day formal comment period.

If a SAR for a new Reliability Standard is posted for a formal comment period, the Standards Committee shall appoint a drafting team to work with the NERC Staff coordinator to give prompt consideration of the written views and objections of all participants. The Standards Committee may use a public nomination process to populate the Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. In some situations, an *ad hoc* team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to refine the SAR and develop the Reliability Standard, and additional members may not be needed. The drafting team shall address all comments submitted, which may be in the form of a summary response addressing each of the issues raised in comments received, during the public posting period. An effort to resolve all expressed objections shall be made, and each objector shall be advised of the disposition of the objection and the reasons therefore. If the drafting team concludes that there is not sufficient stakeholder support to continue to refine the SAR, the team may recommend that the Standards Committee direct curtailment of work on the SAR.

While there is no established limit on the number of times a SAR may be posted for comment, the Standards Committee retains the right to reverse its prior decision and reject a SAR if it believes continued revisions are not productive. The Standards Committee shall notify the sponsor in writing of the rejection within 10 calendar days.

If stakeholders indicate support for the project proposed with the SAR, the drafting team shall present its work to the Standards Committee with a request that the Standards Committee authorize development of the associated Reliability Standard.

The Standards Committee, once again considering the public comments received and their resolution, may then take one of the following actions:

- Authorize drafting the proposed Reliability Standard or revisions to a Reliability Standard.
- Reject the SAR with a written explanation to the sponsor and post that explanation.

4.3: Form Drafting Team

When the Standards Committee is ready to have a drafting team begin work on developing a new or revised Reliability Standard, the Standards Committee shall appoint a drafting team, if one was not already appointed to develop the SAR. If the Standards Committee appointed a drafting team to refine the SAR, the same drafting team shall work to develop the associated Reliability Standard.

If no drafting team is in place, then the Standards Committee may use a public nomination process to populate the Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise, diversity of views and work process skills to accomplish the objectives of the project on a timely basis. In some situations, an ad hoc team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to develop the Reliability Standard, and additional members may not be needed.

The NERC Reliability Standards Staff shall provide one or more members as needed to support the team with facilitation, project management, compliance, legal, regulatory and technical writing expertise and shall provide administrative support to the team, guiding the team through the steps in completing its project. In developing the Reliability Standard, the individuals provided by the NERC Reliability Standards Staff serve as advisors to the drafting team and do not have voting rights but share accountability along with the drafting team members assigned by the Standards Committee for timely delivery of a final draft Reliability Standard that meets the quality attributes identified in NERC's Benchmarks for Excellent Standards. The drafting team members assigned by the Standards Committee shall have final authority over the technical details of the Reliability Standard, while the technical writer shall provide assistance to the drafting team in assuring that the final draft of the Reliability Standard meets the quality attributes identified in NERC's Benchmarks for Excellent Standards.

Once it is appointed by the Standards Committee, the Reliability Standard drafting team is responsible for making recommendations to the Standards Committee regarding the remaining steps in the Reliability Standards process. Consistent with the need to provide for timely standards development, the Standards Committee may decide a project is so large that it should be subdivided and either assigned to more than one drafting team or assigned to a single drafting team with clear direction on completing the project in specified phases. The normally expected timeframes for standards development within the context of this manual are applicable to individual standards and not to projects containing multiple standards. Alternatively, a single drafting team may address the entire project with a commensurate increase in the expected duration of the development work. If a SAR is subdivided and assigned to more than one drafting team, each drafting team will have a clearly defined portion of the work such that there are no overlaps and no gaps in the work to be accomplished.

The Standards Committee may supplement the membership of a Reliability Standard drafting team or provide for additional advisors, as appropriate, to ensure the necessary competencies and diversity of views are maintained throughout the Reliability Standard development effort.

4.4: Develop Preliminary Draft of Reliability Standard, Implementation Plan and VRFs and VSLs

4.4.1: Project Schedule

When a drafting team begins its work, either in refining a SAR or in developing or revising a proposed Reliability Standard, the drafting team shall develop a project schedule which shall be approved by the Standards Committee. The drafting team shall report progress to the Standards Committee, against the initial project schedule and any revised schedule as requested by the Standards Committee. Where project milestones cannot be completed on a timely basis, modifications to the project schedule must be presented to the Standards Committee for consideration along with proposed steps to minimize unplanned project delays.

4.4.2: Draft Reliability Standard

The team shall develop a Reliability Standard that is within the scope of the associated SAR that includes all required elements as described earlier in this manual with a goal of meeting the quality attributes identified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval. The team shall document its justification for the Requirements in its proposed Reliability Standard by explaining how each meets these criteria. The standard drafting team shall document its justification for selecting each reference by explaining how each Requirement fits the category chosen.

4.4.3: Implementation Plan

As a drafting team drafts its proposed revisions to a Reliability Standard, that team is also required to develop an implementation plan to identify any factors for consideration when approving the proposed effective date or dates for the associated Reliability Standard or Standards. As a minimum, the implementation plan shall include the following:

- The proposed effective date (the date entities shall be compliant) for the Requirements.
- Identification of any new or modified definitions that are proposed for approval with the associated Reliability Standard.
- Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the Requirements.
- Whether approval of the proposed Reliability Standard will necessitate any conforming changes to any already approved Reliability Standards – and identification of those Reliability Standards and Requirements.
- The Functional Entities that will be required to comply with one or more Requirements in the proposed Reliability Standard.

A single implementation plan may be used for more than one Reliability Standard. The implementation plan is posted with the associated Reliability Standard or Standards during the 45 (calendar) day formal comment period and is balloted with the associated Reliability Standard.

4.4.4: Violation Risk Factors and Violation Severity Levels

The drafting team shall work with NERC Staff in developing a set of VRFs and VSLs that meet the latest criteria established by NERC and Applicable Governmental Authorities. The drafting team shall document its justification for selecting each VRF and for setting each set of proposed VSLs by explaining how its proposed VRFs and VSLs meet these criteria. NERC Staff is responsible for ensuring that the VRFs and VSLs proposed for stakeholder review meet these criteria.

Before the drafting team has finalized its Reliability Standard, implementation plan, and VRFs and VSLs, the team should seek stakeholder feedback on its preliminary draft documents.

4.5: Informal Feedback[17]

Drafting teams may use a variety of methods to collect informal stakeholder feedback on preliminary drafts of its documents, including the use of informal comment periods,[18] webinars, industry meetings, workshops, or other mechanisms. Information gathered from informal comment forms shall be publicly posted. While drafting teams are not required to provide a written response to each individual comment received, drafting teams are encouraged, where possible, to post a summary response that identifies how it used comments submitted by stakeholders. Drafting teams are encouraged, where possible, to reach out directly to individual stakeholders in order to facilitate resolution of identified stakeholder concerns. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft."

4.6: Conduct Quality Review

The NERC Reliability Standards Staff shall coordinate a quality review of the Reliability Standard, implementation plan, and VRFs and VSLs in parallel with the development of the Reliability Standard and implementation plan, to assess whether the documents are within the scope of the associated SAR, whether the Reliability Standard is clear and enforceable as written, and whether the Reliability Standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of Reliability Standards. The drafting team shall consider the results of the quality review, decide upon appropriate changes, and recommend to the Standards Committee whether the documents are ready for formal posting and balloting.

The Standards Committee shall authorize posting the proposed Reliability Standard, and implementation plan for a formal comment period and ballot and the VRFs and VSLs for a non-binding poll as soon as the work flow will accommodate.

If the Standards Committee finds that any of the documents do not meet the specified criteria, the Standards Committee shall remand the documents to the drafting team for additional work.

If the Reliability Standard is outside the scope of the associated SAR, the drafting team shall be directed to either revise the Reliability Standard so that it is within the approved scope, or submit a request to expand the scope of the approved SAR. If the Reliability Standard is not clear and enforceable as written, or if the Reliability Standard does not meet the specified criteria, the Reliability Standard shall be returned to the drafting team by the Standards Committee with specific identification of any Requirement that is deemed to be unclear or unenforceable as written.

4.7: Conduct Formal Comment Period and Ballot

Proposed new or modified Reliability Standards require a formal comment period where the new or modified Reliability Standard, implementation plan and associated VRFs and VSLs or the proposal to retire a Reliability Standard, implementation plan and associated VRFs and VSLs are posted.

The formal comment period shall be at least 45-days long. Formation of the ballot pool and Ballot of the Reliability Standard take place during this formal 45-day comment period. The intent of the formal comment period(s) is to solicit very specific feedback on the final draft of the Reliability Standard, implementation plan and VRFs and VSLs.

[17] While this discussion focuses on collecting stakeholder feedback on proposed Reliability Standards and implementation plans, the same process is used to collect stakeholder feedback on proposed new or modified Interpretations, definitions and Variances.

[18] The term "informal comment period" refers to a comment period conducted outside of the ballot process and where there is no requirement for a drafting team to respond in writing to submitted comments.

Comments in written form may be submitted on a draft Reliability Standard by any interested stakeholder, including NERC Staff, FERC Staff, and other interested governmental authorities. If stakeholders disagree with some aspect of the proposed set of products, comments provided should explain the reasons for such disagreement and, where possible, suggest specific language that would make the product acceptable to the stakeholder.

4.8: Form Ballot Pool

The NERC Reliability Standards Staff shall establish a ballot pool during the first 30 calendar days of the 45-day formal comment period. The NERC Reliability Standards Staff shall post the proposed Reliability Standard, along with its implementation plan, VRFs and VSLs and shall send a notice to every entity in the Registered Ballot Body to provide notice that there is a new or revised Reliability Standard proposed for approval and to solicit participants for the associated ballot pool. All members of the Registered Ballot Body are eligible to join each ballot pool to vote on a new or revised Reliability Standard and its implementation plan and to participate in the non-binding poll of the associated VRFs and VSLs.

Any member of the Registered Ballot Body may join or withdraw from the ballot pool until the ballot window opens. No Registered Ballot Body member may join or withdraw from the ballot pool once the first ballot starts through the point in time where balloting for that Reliability Standard action has ended. The Director of Standards may authorize deviations from this rule for extraordinary circumstances such as the death, retirement, or disability of a ballot pool member that would prevent an entity that had a member in the ballot pool from eligibility to cast a vote during the ballot window. Any approved deviation shall be documented and noted to the Standards Committee.

4.9: Conduct Ballot and Non-binding Poll of VRFs and VSLs[19]

The NERC Reliability Standards Staff shall announce the opening of the Ballot window and the non-binding poll of VRFs and VSLs. The Ballot window and non-binding poll of VRFs and VSLs shall take place during the last 10 calendar days of the 45-day formal comment period and for the Final Ballot shall be no less than 10 calendar days. If the last day of the ballot window falls on a Saturday or Sunday, the period does not end until the next business day.[20]

The ballot and non-binding poll shall be conducted electronically. The voting window shall be for a period of 10 calendar days but shall be extended, if needed, until a quorum is achieved. During a ballot window, NERC shall not sponsor or facilitate public discussion of the Reliability Standard action under ballot.

There is no requirement to conduct a new non-binding poll of the revised VRFs and VSLs if no changes were made to the associated standard, however if the requirements are modified and conforming changes are made to the associated VRFs and VSLs, another non-binding poll of the revised VRFs and VSLs shall be conducted.

[19] While RSAWs are not part of the Reliability Standard, they are developed through collaboration of the SDT and NERC Compliance Staff. A non-binding poll, similar to what is done for VRFs and VSLs may be conducted for the RSAW developed through this process to gauge industry support for the companion RSAW to be provided for informational purposes to the NERC Board of Trustees.

[20] Closing dates may be extended as deemed appropriate by NERC Staff.

4.10: Criteria for Ballot Pool Approval

Ballot pool approval of a Reliability Standard requires:

A quorum, which is established by at least 75% of the members of the ballot pool submitting a response; and

A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast is the sum of affirmative votes and negative votes with comments. This calculation of votes for the purpose of determining consensus excludes (i) abstentions, (ii) non-responses, and (iii) negative votes without comments.

The following process[21] is used to determine if there are sufficient affirmative votes.

- For each Segment with ten or more voters, the following process shall be used: The number of affirmative votes cast shall be divided by the sum of affirmative and negative votes with comments cast to determine the fractional affirmative vote for that Segment. Abstentions, non-responses, and negative votes without comments shall not be counted for the purposes of determining the fractional affirmative vote for a Segment.
- For each Segment with less than ten voters, the vote weight of that Segment shall be proportionally reduced. Each voter within that Segment voting affirmative or negative with comments shall receive a weight of 10% of the Segment vote.
- The sum of the fractional affirmative votes from all Segments divided by the number of Segments voting[22] shall be used to determine if a two-thirds majority has been achieved. (A Segment shall be considered as "voting" if any member of the Segment in the ballot pool casts either an affirmative vote or a negative vote with comments.)
- A Reliability Standard shall be approved if the sum of fractional affirmative votes from all Segments divided by the number of voting Segments is at least two thirds.

4.11: Voting Positions

Each member of the ballot pool may **only** vote one of the following positions on the Ballot and Additional Ballot(s):

- Affirmative;
- Affirmative, with comment;
- Negative with comments;
- Abstain.

Given that there is no formal comment period concurrent with the Final Ballot, each member of the ballot pool may **only** vote one of the following positions on the Final Ballot:

- Affirmative;
- Negative;[23]
- Abstain.

[21] Examples of weighted segment voting calculation are posted on the Reliability Standards Resources web page.

[22] When less than ten entities vote in a Segment, the total weight for that Segment shall be determined as one tenth per entity voting, up to ten.

[23] The Final Ballot is used to confirm consensus achieved during the Formal Comment and Ballot stage. Ballot Pool members voting negative on the Final Ballot will be deemed to have expressed the reason for their negative ballot in their own comments or the comments of others during prior Formal Comment periods.

4.12: Consideration of Comments
If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

4.13: Additional Ballots
A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted.

However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.

4.14: **Conduct Final Ballot**
When the drafting team has reached a point where it has made a good faith effort at resolving applicable objections and is not making any substantive changes from the previous ballot, the team shall conduct a "Final Ballot." A non-substantive revision is a revision that does not change the scope, applicability, or intent of any Requirement and includes but is not limited to things such as correcting the numbering of a Requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a Requirement for improved clarity. Where there is a question as to whether a proposed modification is "substantive," the Standards Committee shall make the final determination.

In the Final Ballot, members of the ballot pool shall again be presented the proposed Reliability Standard along with the reasons for negative votes from the previous ballot, the responses of the drafting team to those concerns, and any resolution of the differences.

All members of the ballot pool shall be permitted to reconsider and change their vote from the prior ballot. Members of the ballot pool who did not respond to the prior ballot shall be permitted to vote in the Final Ballot. In the Final Ballot, votes shall be counted by exception only — members on the Final Ballot may indicate a revision to their original vote; otherwise their vote shall remain the same as in their prior ballot.

4.15: Final Ballot Results
There are no limits to the number of public comment periods and ballots that can be conducted to result in a Reliability Standard or interpretation that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval. The Standards Committee has the authority to conclude this process for a particular Reliability Standards action if it becomes obvious that the drafting team cannot develop a Reliability Standard that is within the scope of the associated SAR, is sufficiently clear to be enforceable, and achieves the requisite weighted Segment approval percentage.

The NERC Reliability Standards Staff shall post the final outcome of the ballot process. If the Reliability Standard is rejected, the Standards Committee may decide whether to end all further work on the proposed standard, return the project to informal development, or continue holding ballots to attempt to reach

consensus on the proposed standard. If the Reliability Standard is approved, the Reliability Standard shall be posted and presented to the Board of Trustees by NERC management for adoption and subsequently filed with Applicable Governmental Authorities for approval.

4.16: Board of Trustees Adoption of Reliability Standards, Implementation Plan and VRFs and VSLs

If a Reliability Standard and its associated implementation plan are approved by its ballot pool, the Board of Trustees shall consider adoption of that Reliability Standard and its associated implementation plan and shall direct the standard to be filed with Applicable Governmental Authorities for approval. In making its decision, the Board shall consider the results of the balloting and unresolved dissenting opinions. The Board shall adopt or reject a Reliability Standard and its implementation plan, but shall not modify a proposed Reliability Standard. If the Board chooses not to adopt a Reliability Standard, it shall provide its reasons for not doing so.

The board shall consider approval of the VRFs and VSLs associated with a reliability standard. In making its determination, the board shall consider the following:

- The Standards Committee shall present the results of the non-binding poll conducted and a summary of industry comments received on the final posting of the proposed VRFs and VSLs.
- NERC Staff shall present a set of recommended VRFs and VSLs that considers the views of the standard drafting team, stakeholder comments received on the draft VRFs and VSLs during the posting for comment process, the non-binding poll results, appropriate governmental agency rules and directives, and VRF and VSL assignments for other Reliability Standards to ensure consistency and relevance across the entire spectrum of Reliability Standards.

4.17: Compliance

For a Reliability Standard to be enforceable, it shall be approved by its ballot pool, adopted by the NERC Board of Trustees, and approved by Applicable Governmental Authorities, unless otherwise approved by the NERC Board of Trustees pursuant to the NERC Rules of Procedure (*e.g*, Section 321) and approved by Applicable Governmental Authorities. Once a Reliability Standard is approved or otherwise made mandatory by Applicable Governmental Authorities, all persons and organizations subject to jurisdiction of the ERO will be required to comply with the Reliability Standard in accordance with applicable statutes, regulations, and agreements.

4.18: Withdrawal of a Reliability Standard, Interpretation, or Definition

The term "withdrawal" as used herein, refers to the discontinuation of a Reliability Standard, Interpretation, Variance or definition that has been approved by the Board of Trustees and (1) has not been filed with Applicable Governmental Authorities, or (2) has been filed with, but not yet approved by, Applicable Governmental Authorities. The Standards Committee may withdraw a Reliability Standard, Interpretation or definition for good cause upon approval by the Board of Trustees. Upon approval by the Board of Trustees, NERC Staff will petition the Applicable Governmental Authorities, as needed, to allow for withdrawal. The Board of Trustees also has an independent right of withdrawal that is unaffected by the terms and conditions of this Section.

4.19: Retirement of a Reliability Standard, Interpretation, or Definition

The term "retirement" refers to the discontinuation of a Reliability Standard, Interpretation or definition that has been approved by Applicable Governmental Authorities. A Reliability Standard, Variance or Definition may be retired when it is superseded by a revised version, and in such cases the retirement of the

earlier version is to be noted in the implementation plan presented to the ballot pool for approval and the retirement shall be considered approved by the ballot pool upon ballot pool approval of the revised version.

Upon identification of a need to retire a Reliability Standard, Variance, Interpretation or definition, where the item will not be superseded by a new or revised version, a SAR containing the proposal to retire a Reliability Standard, Variance, Interpretation or definition will be posted for a comment period and ballot in the same manner as a Reliability Standard. The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Power System. Upon approval by the Board of Trustees, NERC Staff will petition the Applicable Governmental Authorities to allow for retirement.

Section 5.0: Process for Developing a Defined Term

NERC maintains a glossary of approved terms, entitled the *Glossary of Terms Used in NERC Reliability Standards*[24] ("Glossary of Terms"). The Glossary of Terms includes terms that have been through the formal approval process and are used in one or more NERC Reliability Standards. Definitions shall not contain statements of performance Requirements. The Glossary of Terms is intended to provide consistency throughout the Reliability Standards.

There are several methods that can be used to add, modify or retire a defined term used in a continent-wide Reliability Standard.

- Anyone can use a Standard Authorization Request ("SAR") to submit a request to add, modify, or retire a defined term.
- Anyone can submit a Standards Comments and Suggestions Form recommending the addition, modification, or retirement of a defined term. (The suggestion would be added to a project and incorporated into a SAR.)
- A drafting team may propose to add, modify, or retire a defined term in conjunction with the work it is already performing.

5.1: Proposals to Develop a New or Revised Definition

The following considerations should be made when considering proposals for new or revised definitions:

- Some NERC Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by a Regional Entity, the same definition should be adopted if needed to support a NERC Reliability Standard.
- If a term is used in a Reliability Standard according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the Glossary of Terms.
- If a term has already been defined, any proposal to modify or delete that term shall consider all uses of the definition in approved Reliability Standards, with a goal of determining whether the proposed modification is acceptable, and whether the proposed modification would change the scope or intent of any approved Reliability Standards.
- When practical, where NAESB has a definition for a term, the drafting team shall use the same definition to support a NERC Reliability Standard.

Any definition that is balloted separately from a proposed new or modified Reliability Standard or from a proposal for retirement of a Reliability Standard shall be accompanied by an implementation plan.

If a SAR is submitted to the NERC Reliability Standards Staff with a proposal for a new or revised definition, the Standards Committee shall consider the urgency of developing the new or revised definition and may direct NERC Staff to post the SAR immediately, or may defer posting the SAR until a later time based on its priority relative to other projects already underway or already approved for future development. If the SAR identifies a term that is used in a Reliability Standard already under revision by a drafting team, the Standards Committee may direct the drafting team to add the term to the scope of the existing project. Each time the Standards Committee accepts a SAR for a project that was not identified in the *Reliability Standards Development Plan,* the project shall be added to the list of approved projects.

[24] The latest approved version of the Glossary of Terms is posted on the NERC website on the Standards web page.

5.2: Stakeholder Comments and Approvals

Any proposal for a new or revised definition shall be processed in the same manner as a Reliability Standard and quality review shall be conducted in parallel with this process. Once authorized by the Standards Committee, the proposed definition and its implementation plan shall be posted for at least one formal stakeholder comment period and shall be balloted in the same manner as a Reliability Standard. If a new or revised definition is proposed by a drafting team, that definition may be balloted separately from the associated Reliability Standard.

Each definition that is approved by its ballot pool shall be submitted to the NERC Board of Trustees for adoption and then filed with Applicable Governmental Authorities for approval in the same manner as a Reliability Standard.

Section 6.0: Processes for Conducting Field Tests and Collecting and Analyzing Data

While most drafting teams can develop their Reliability Standards without the need to conduct any field tests and without the need to collect and analyze data, some Reliability Standard development efforts may require field tests to analyze data and validate concepts in the development of Reliability Standards. Drafting teams are not required to collect and analyze data or to conduct a field test to validate a Reliability Standard.

6.1: Field Tests and Data Analysis for Validation of Concepts(collectively "Field Test")

1. Field tTests or collection and analysis of data to validate concepts that support the development of Requirements should be conducted before the SAR Standard Authorization Request ("SAR") for a project is finalized.
   If an entity wants to test a technical concept in support of a proposal for a new or revised Reliability Standard, the entity should either work with one of NERC's technical committees in collecting and analyzing the data or in conducting the field test, or the entity should submit a SAR with a request to collect and analyze data or conduct a field test to validate the concept prior to developing a new or revised Reliability Standard. The request to collect and analyze data or conduct a field test should include, at a minimum, either the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the analysis of the results. If the SAR sponsor has not collected and analyzed the data or conducted the field test, the Standards Committee may solicit support from NERC's technical committees or others in the industry. The results of the data collection and analysis or field test shall then be used to determine whether to add the SAR to the list of projects in the Reliability Standard Development Plan.
2. To conduct a Field Test of a technical concept in a proposed new or revised Reliability Standard, the requesting team must work with NERC staff to identify one of NERC's technical committees to lead the effort in conducting the Field Test.

6.1.1: Field Test Approval

The request to conduct a Field Test must include, at a minimum:

- the Field Test plan,
- the implementation schedule, and
- an expectation for periodic updates of the analysis of the results.

Prior to the requesting team conducting a Field Test, it must:

- first receive approval from the lead NERC technical committee, and
- subsequently receive approval from the Standards Committee.

6.1.2: Field Test Suspension

During the Field Test, if the lead NERC technical committee overseeing the Field Test determines there is a reliability risk to the BES:

- the lead NERC technical committee shall stop or modify the activity;
- the lead NERC technical committee shall inform the Standards Committee that the activity was stopped or modified;

- the Standards Committee, with the assistance of NERC staff, shall document the cessation or modification of the Field Test; and
- the Standards Committee shall notify NERC compliance staff to coordinate any compliance related issues such as continuance or cessation of waivers.

Prior to the Field Test being restarted after it has been stopped, the requesting team must resubmit the Field Test and receive approval as outlined in section 6.1.1.

If the Field Test does not provide sufficient information to formulate a conclusion within the time allotted in the plan, the Chair of the Standards Committee will work with the requesting team and the lead NERC technical committee to determine whether to continue, modify or terminate the Field Test.

If ~~a drafting team finds that it~~ the requesting team determines a need~~s~~ to ~~collect and analyze data or~~ conduct a ~~field~~ Field ~~test~~ Test of a concept that was not identified ~~when~~ in the SAR ~~was accepted, then the Standards Committee may direct the team to withdraw the SAR until the data has been collected and analyzed or until the field test has been conducted and the industry has had an opportunity to review the results for the impact on the scope of the proposed project~~it must create a supplemental SAR to include the Field Test and receive approval as outlined in section 6.1.1.

~~6.2: Field Tests and Data Analysis for Validation of Requirements~~

~~If a drafting team wants to conduct a field test or collect and analyze data to validate its proposed Requirements in a Reliability Standard, the team shall first obtain approval from the Standards Committee.[25] Drafting teams are not required to collect and analyze data or to conduct a field test to validate a Reliability Standard.~~

~~The request should include at a minimum the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the results. When authorizing a drafting team to collect and analyze data or to conduct a field test of one or more Requirements, the Standards Committee may request inputs on technical matters related from NERC's technical committees or industry experts, and may request the assistance of the Compliance Monitoring and Enforcement Program. All data collection and analysis and all field tests shall be concluded and the results incorporated into the Reliability Standard Requirements as necessary before proceeding to the formal comment period and subsequent balloting.~~

6.~~3~~2: Communication and Coordination for All Types of Field Tests ~~and Data Analyses~~

~~If the conduct of a field test (concepts or Requirements) or data collection and analysis could~~After approval of the Field Test, the requesting team may request waivers of compliance for Field Test participants that would be rendered ~~render Registered Entities~~ incapable of complying with the ~~current~~ Requirement(s) of ~~an approved~~the currently enforceable Reliability Standard ~~that is undergoing revision, the drafting team shall request a temporary waiver from compliance to those Requirements for entities participating in the field test~~due to their participation. ~~Upon request, the Standards Committee shall seek approval for the waiver from t~~The Compliance Monitoring and Enforcement Program staff ~~prior to the approval of the field test or data collection and analysis~~shall determine whether to approve the requested waivers, and the Standards staff shall inform the affected registered entities. Prior to initiation of the Field Test, the Chair of the Standards Committee, in conjunction with the lead NERC technical committee chair, shall inform the

[25] ~~The Process for Approving Data Collection and Analysis and Field Tests Associated with a Reliability Standard is posted on the Reliability Standards Resources web page.~~

NERC Board of the pending Field Test, the expected duration, and any requested waivers from compliance for registered entities.

During the Field Test, the requesting team conducting the Field Test shall provide periodic updates (no less than quarterly) on the progress of the Field Tests to the Standards Committee and the applicable NERC technical committees. The Chair of the Standards Committee shall keep the NERC Board informed.

Once a plan for a field test or a plan for data collection and analysis is approved, the NERC Reliability Standards Staff shall, under the direction of the Standards Committee, coordinate the implementation of the field test or data collection and analysis and shall provide official notice to the participants in the field test or data collection of any applicable temporary waiver to compliance with specific noted Requirements. The drafting team conducting the field test shall provide periodic updates on the progress of the field tests or data collection and analysis to the Standards Committee. The Standards Committee has the right to curtail a field test or data collection and analysis that is not implemented in accordance with the approved plan.

The field test plan or data collection and analysis plan, its approval, its participants, and all reports and results shall be publicly posted for stakeholder review on the Reliability Standards web page.

If a drafting team conducts or participates in a field test or in data collection and analysis (of concepts or Requirements), it shall provide a final report that identifies the results and how those results will be used.

Section 7.0: Process for Developing an Interpretation

A valid Interpretation request is one that requests additional clarity about one or more Requirements in approved NERC Reliability Standards, but does not request approval as to how to comply with one or more Requirements. A valid Interpretation response provides additional clarity about one or more Requirements, but does not expand on any Requirement and does not explain how to comply with any Requirement. Any entity that is directly and materially affected by the reliability of the North American Bulk Power Systems may request an Interpretation of any Requirement in any continent-wide Reliability Standard that has been adopted by the NERC Board of Trustees. Interpretations will only be provided for Board of Trustees-approved Reliability Standards *i.e.* (i) the current effective version of a Reliability Standard; or (ii) a version of a Reliability Standard with a future effective date.

An Interpretation may only clarify or interpret the Requirements of an approved Reliability Standard, including, if applicable, any attachment referenced in the Requirement being clarified. No other elements of an approved Reliability Standard are subject to Interpretation.

The entity requesting the Interpretation shall submit a *Request for Interpretation* form[26] to the NERC Reliability Standards Staff explaining the clarification required, the specific circumstances surrounding the request, and the impact of not having the Interpretation provided. The NERC Reliability Standards and Legal Staffs shall review the request for interpretation to determine whether it meets the requirements for a valid interpretation. Based on this review, the NERC Standards and Legal Staffs shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request.

For example, an Interpretation request may be rejected where it:

(1) Requests approval of a particular compliance approach;
(2) Identifies a gap or perceived weakness in the approved Reliability Standard;
(3) Where an issue can be addressed by an active standard drafting team;
(4) Where it requests clarification of any element of a Reliability Standard other than a Requirement;
(5) Where a question has already been addressed in the record;
(6) Where the Interpretation identifies an issue and proposes the development of a new or modified Reliability Standard, (such issues should be addressed via submission of a SAR);
(7) Where an Interpretation seeks to expand the scope of a Reliability Standard; or
(8) Where the meaning of a Reliability Standard is plain on its face.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the Interpretation within 10 business days of the decision to reject. If the Standards Committee accepts the Interpretation request, the NERC Standards Staff shall (i) form a ballot pool and (ii) assemble an Interpretation drafting team with the relevant expertise to address the interpretation for approval by the Standards Committee. As soon as practical, the team shall develop a "final draft" Interpretation providing the requested clarity.

Interpretations will be balloted in the same manner as Reliability Standards.

[26] The *Request for Interpretation* form is posted on the NERC Standards web page.

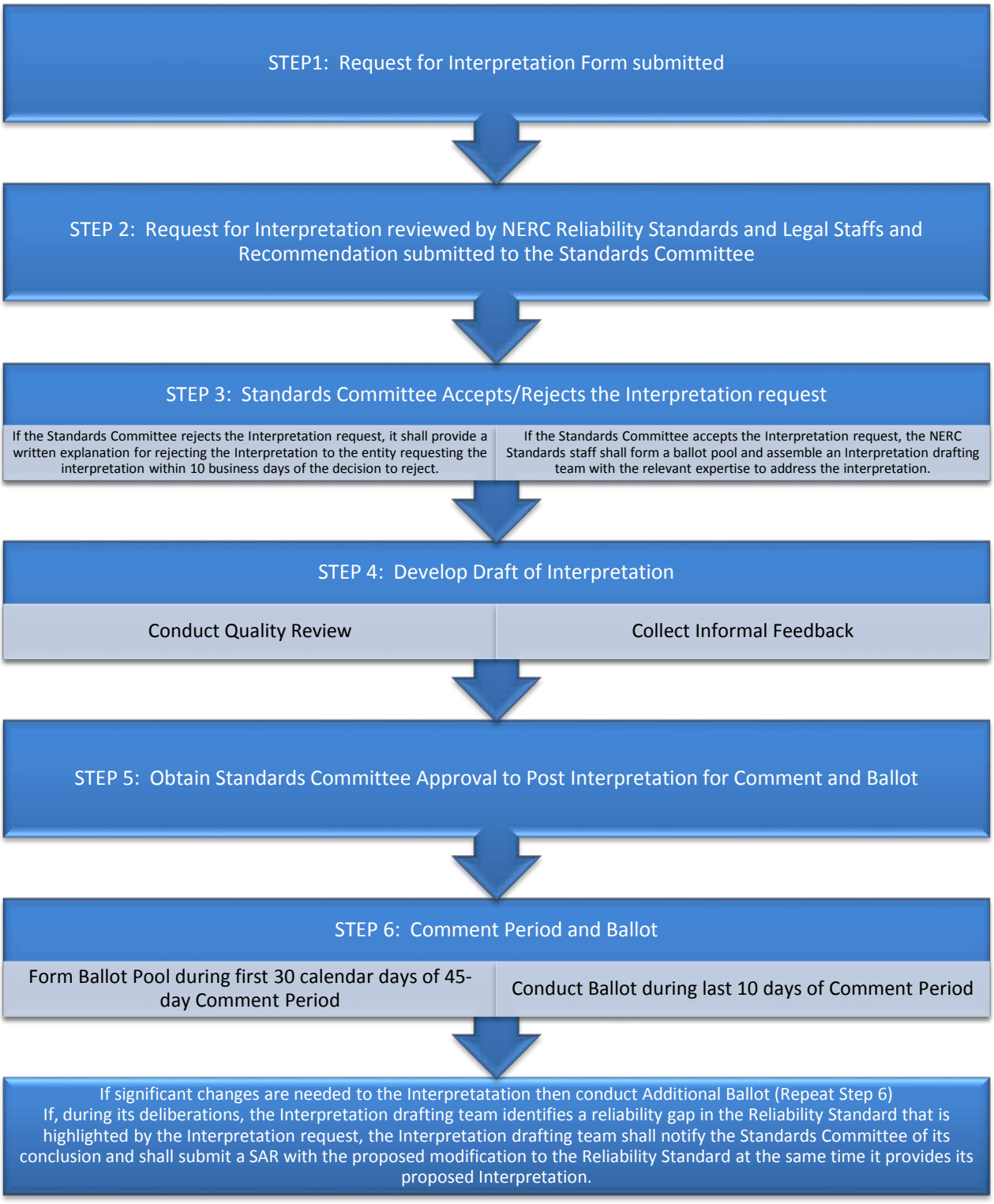
If stakeholder comments indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic expectations outlined above, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with the proposed modification to the Reliability Standard. The entity that requested the Interpretation shall be notified and the disposition of the Interpretation shall be posted.

If, during its deliberations, the Interpretation drafting team identifies a reliability gap in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with the proposed modification to the Reliability Standard at the same time it provides its proposed Interpretation.

The NERC Reliability Standards and Legal Staffs shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation. Based on this review, the NERC Standards and Legal Staffs shall make a recommendation to the NERC Board of Trustees regarding adoption.

If approved by its ballot pool, the Interpretation shall be forwarded to the NERC Board of Trustees for adoption.[27] If an Interpretation drafting team proposes a modification to a Reliability Standard as part of its work in developing an Interpretation, the Board of Trustees shall be notified of this proposal at the time the Interpretation is submitted for adoption. Following adoption by the Board of Trustees, NERC Staff shall file the Interpretation for approval by Applicable Governmental Authorities and the Interpretation shall become effective when approved by those Applicable Governmental Authorities. The Interpretation shall stand until such time as the Interpretation can be incorporated into a future revision of the Reliability Standard or the Interpretation is retired due to a future modification of the applicable Requirement.

[27] NERC will maintain a record of all interpretations associated with each standard on the Reliability Standards page of the NERC website.


STEP1: Request for Interpretation Form submitted
STEP 2: Request for Interpretation reviewed by NERC Reliability Standards and Legal Staffs and Recommendation submitted to the Standards Committee
STEP 3: Standards Committee Accepts/Rejects the Interpretation request
If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the interpretation within 10 business days of the decision to reject.
If the Standards Committee accepts the Interpretation request, the NERC Standards staff shall form a ballot pool and assemble an Interpretation drafting team with the relevant expertise to address the interpretation.
STEP 4: Develop Draft of Interpretation
Conduct Quality Review
Collect Informal Feedback
STEP 5: Obtain Standards Committee Approval to Post Interpretation for Comment and Ballot
STEP 6: Comment Period and Ballot
Form Ballot Pool during first 30 calendar days of 45-day Comment Period
Conduct Ballot during last 10 days of Comment Period
If significant changes are needed to the Interpretatation then conduct Additional Ballot (Repeat Step 6)
If, during its deliberations, the Interpretation drafting team identifies a reliability gap in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and shall submit a SAR with the proposed modification to the Reliability Standard at the same time it provides its proposed Interpretation.

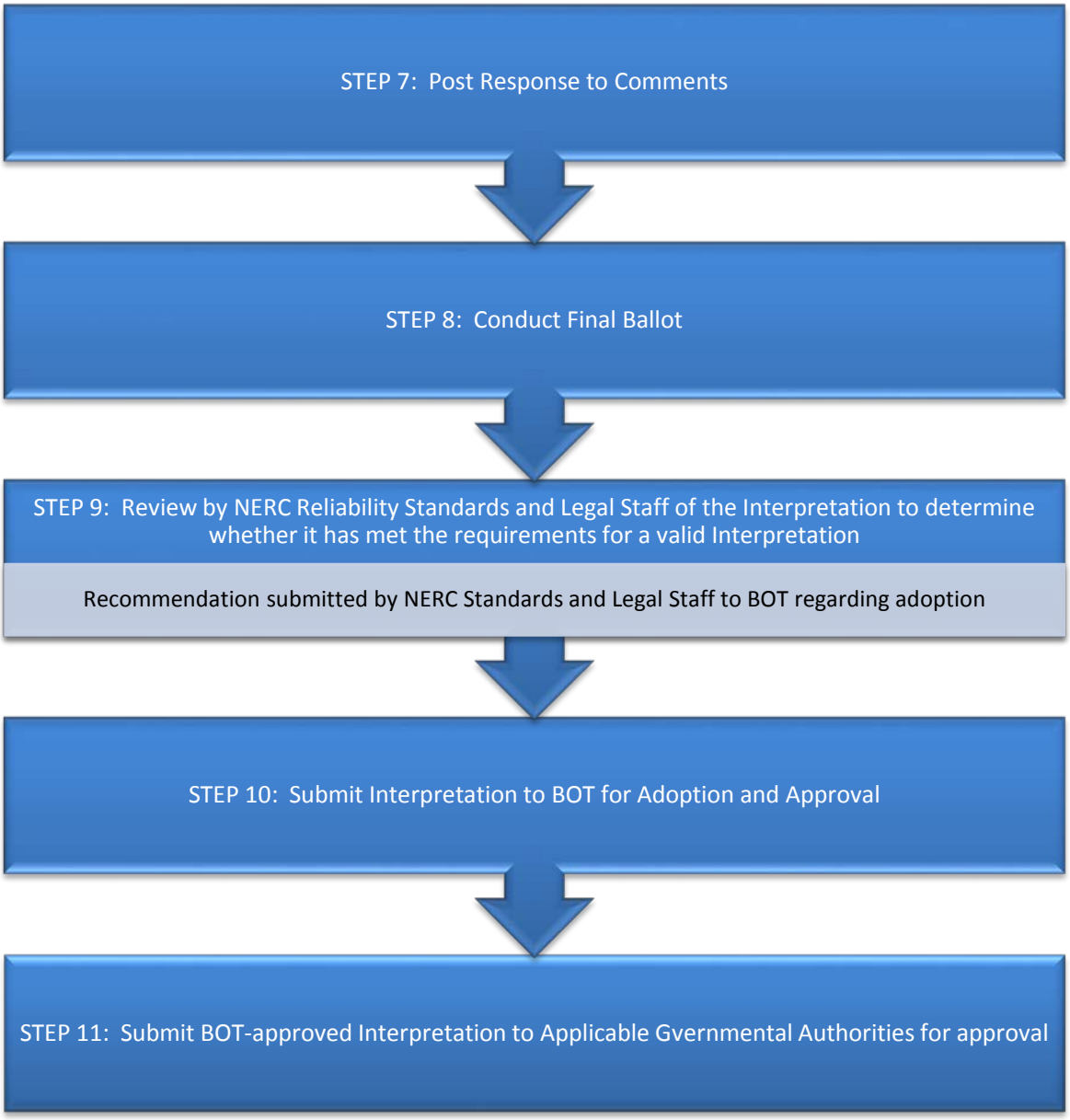


FIGURE 2: Process for Developing an Interpretation

Section 8.0: Process for Appealing an Action or Inaction

Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, retirement or withdrawal of a Reliability Standard, definition, Variance, associated implementation plan, or Interpretation shall have the right to appeal. This appeals process applies only to the NERC Reliability Standards processes as defined in this manual, not to the technical content of the Reliability Standards action.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made in writing within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants.

8.1: Level 1 Appeal

Level 1 is the required first step in the appeals process. The appellant shall submit (to the Director of Standards) a complaint in writing that describes the procedural action or inaction associated with the Reliability Standards process. The appellant shall describe in the complaint the actual or potential adverse impact to the appellant. Assisted by NERC Staff and industry resources as needed, the Director of Standards shall prepare a written response addressed to the appellant as soon as practical but not more than 45 days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response shall be made a part of the public record associated with the Reliability Standard.

8.2: Level 2 Appeal

If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to the Director of Standards, the Director of Standards shall convene a Level 2 Appeals Panel. This panel shall consist of five members appointed by the Board of Trustees. In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The NERC Reliability Standards Staff shall post the complaint and other relevant materials and provide at least 30 days notice of the meeting of the Level 2 Appeals Panel. In addition to the appellant, any entity that is directly and materially affected by the procedural action or inaction referenced in the complaint shall be heard by the panel. The panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The panel may, in its decision, find for the appellant and remand the issue to the Standards Committee with a statement of the issues and facts in regard to which fair and equitable action was not taken. The panel may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, disapprove, or adopt a Reliability Standard, definition, Variance or Interpretation or implementation plan as these responsibilities remain with the ballot pool and Board of Trustees respectively. The actions of the Level 2 Appeals Panel shall be publicly posted.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the Board of Trustees for consideration at the time the Board decides whether to adopt a particular Reliability Standard, definition, Variance or Interpretation. The objection shall be in writing, signed by an officer of the objecting entity, and contain a concise statement of the relief requested and a clear demonstration of the

facts that justify that relief. The objection shall be filed no later than 30 days after the announcement of the vote by the ballot pool on the Reliability Standard in question.

Section 9.0: Process for Developing a Variance

A Variance is an approved, alternative method of achieving the reliability intent of one or more Requirements in a Reliability Standard. No Regional Entity or Bulk Power System owner, operator, or user shall claim a Variance from a NERC Reliability Standard without approval of such a Variance through the relevant Reliability Standard approval procedure for the Variance. Each Variance from a NERC Reliability Standard that is approved by NERC and Applicable Governmental Authorities shall be made an enforceable part of the associated NERC Reliability Standard.

NERC's drafting teams shall aim to develop Reliability Standards with Requirements that apply on a continent-wide basis, minimizing the need for Variances while still achieving the Reliability Standard's reliability objectives. If one or more Requirements cannot be met or complied with as written because of a physical difference in the Bulk Power System or because of an operational difference (such as a conflict with a federally or provincially approved tariff), but the Requirement's reliability objective can be achieved in a different fashion, an entity or a group of entities may pursue a Variance from one or more Requirements in a continent-wide Reliability Standard. It is the responsibility of the entity that needs a Variance to identify that need and initiate the processing of that Variance through the submittal of a SAR[28] that includes a clear definition of the basis for the Variance.

There are two types of Variances – those that apply on an Interconnection-wide basis, and those that apply to one or more entities on less than an Interconnection-wide basis.

9.1: Interconnection-wide Variances

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to Registered Entities within a Regional Entity organized on an Interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that Regional Entity's NERC-approved Regional Reliability Standards development procedure.

While an Interconnection-wide Variance may be developed through the associated Regional Reliability Standards development process, Regional Entities are encouraged to work collaboratively with existing continent-wide drafting teams to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC Reliability Standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC Reliability Standard that is developed, in accordance with a Regional Reliability Standards development procedure approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

9.2: Variances that Apply on Less than an Interconnection-wide Basis

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to one or more entities but less than an entire Interconnection (*e.g.*, a Variance that would apply to a regional transmission organization or particular market or to a subset of Bulk Power System owners, operators, or users), shall be considered a Variance. A Variance may be requested while a Reliability Standard is under development or a Variance may be requested at any time after a Reliability Standard is approved. Each request for a

[28] A sample of a SAR that identifies the need for a Variance and a sample Variance are posted as resources on the Reliability Standards Resources web page.

Variance shall be initiated through a SAR, and processed and approved in the same manner as a continent-wide Reliability Standard, using the Reliability Standards development process defined in this manual.

Section 10.0: Processes for Developing a Reliability Standard Related to a Confidential Issue

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC has an obligation as the ERO to ensure that there are Reliability Standards in place to preserve the reliability of the interconnected Bulk Power Systems throughout North America. When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as American National Standards.

The NERC Board of Trustees may direct the development of a new or revised Reliability Standard to address a national security situation that involves confidential issues. These situations may involve imminent or long-term threats. In general, these Board directives will be driven by information from the President of the United States of America or the Prime Minister of Canada or a national security agency or national intelligence agency of either or both governments indicating (to the ERO) that there is a national security threat to the reliability of the Bulk Power System.[29]

There are two special processes for developing Reliability Standards responsive to confidential issues – one process where the confidential issue is "imminent," and one process where the confidential issue is "not imminent."

10.1: Process for Developing Reliability Standards Responsive to Imminent, Confidential Issues
If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards Staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.2: Drafting Team Selection
The Reliability Standard drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.3: Work of Drafting Team
The Reliability Standard drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The Reliability Standard drafting team shall review its work, to the extent practical, as it is being developed with officials from the appropriate governmental agencies in the U.S. and Canada, under strict security and confidentiality rules.

10.4: Formal Stakeholder Comment & Ballot Window

[29] The NERC Board may direct the immediate development and issuance of a Level 3 (Essential Action) alert and then may also direct the immediate development of a new or revised Reliability Standard.

The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[30] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards Staff shall not post or provide the ballot pool with any confidential background information.

The drafting team, working with the NERC Reliability Standards Staff, shall consider and respond to all comments, make any necessary conforming changes to the Reliability Standard and its implementation plan, and shall distribute the comments, responses and any revision to the same population as received the initial set of documents for formal comment and ballot.

10.5: Board of Trustee Actions
Each Reliability Standard and implementation plan developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.6: Governmental Approvals
All approved documents shall be filed for approval with Applicable Governmental Authorities.

[30] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

10.7: Developing a Reliability Standard Responsive to an Imminent, Confidential Issue

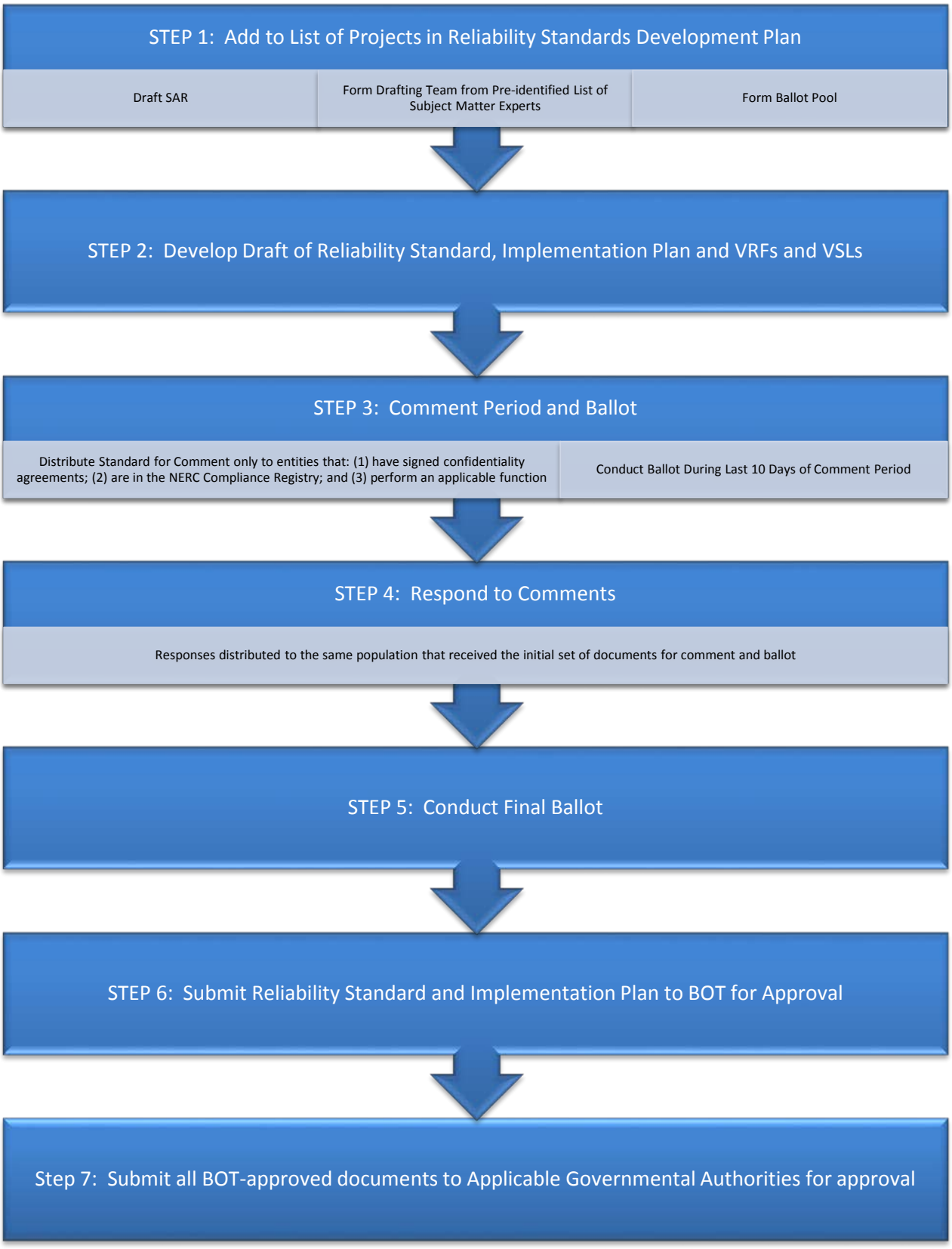


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

10.8: Process for Developing Reliability Standards Responsive to Non-imminent, Confidential Issues

If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards Staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.9: Drafting Team Selection

The drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.10: Work of Drafting Team

The drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The drafting team shall review its work, to the extent practical, as it is being developed with officials from the Applicable Governmental Authorities, under strict security and confidentiality rules.

10.11: Formal Stakeholder Comment & Ballot Window

The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[31] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards Staff shall not post or provide the ballot pool with any confidential background information.

10.12: Revisions to Reliability Standard, Implementation Plan and VRFs and VSLs

The drafting team, working with the NERC Reliability Standards Staff, shall work to refine the Reliability Standard, implementation plan and VRFs and VSLs in the same manner as for a new Reliability Standard following the "normal" Reliability Standards development process described earlier in this manual with the exception that distribution of the comments, responses, and new drafts shall be limited to those entities that are in the ballot pool and those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.

10.13: Board of Trustee Action

Each Reliability Standard, implementation plan, and the associated VRFs and VSLs developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.14: Governmental Approvals

All BOT-approved documents shall be filed for approval with Applicable Governmental Authorities.

[31] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

Developing a Reliability Standard Responsive to a Non-imminent, Confidential Issue

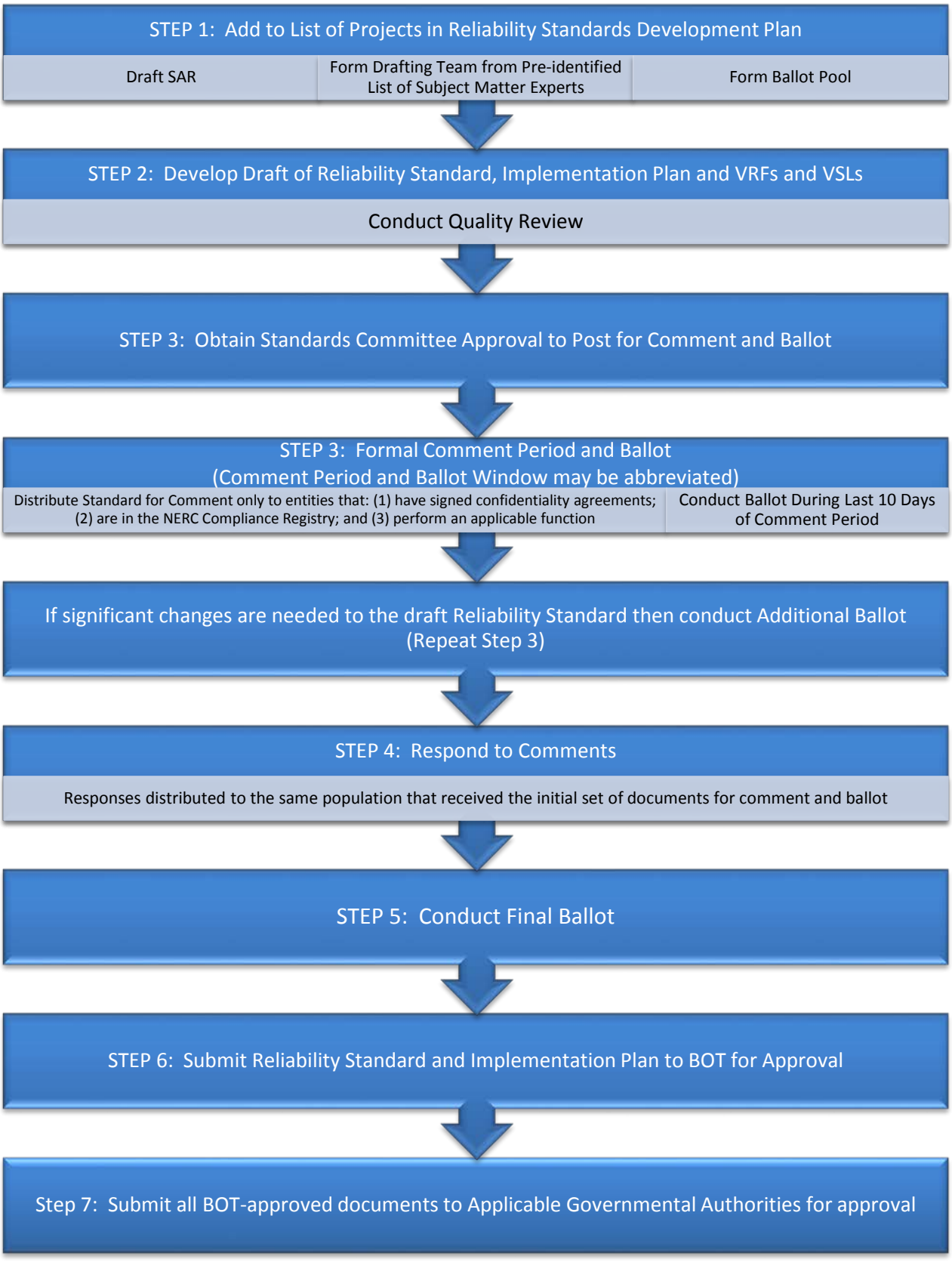


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for Approving Supporting Documents

The following types of documents are samples of the types of supporting documents that may be developed to enhance stakeholder understanding and implementation of a Reliability Standard. These documents may explain or facilitate implementation of Reliability Standards but do not themselves contain mandatory Requirements subject to compliance review. Any Requirements that are mandatory shall be incorporated into the Reliability Standard in the Reliability Standard development process.

While most supporting documents are developed by the standard drafting team working to develop the associated Reliability Standard, any entity may develop a supporting document associated with a Reliability Standard.

The Standards Committee shall authorize the posting of all supporting references[32] that are linked to an approved Reliability Standard. Prior to granting approval to post a supporting reference with a link to the associated Reliability Standard, the Standards Committee shall verify that the document has had stakeholder review to verify the accuracy of the technical content. While the Standards Committee has the authority to approve the posting of each such reference, stakeholders, not the Standards Committee, verify the accuracy of the document's contents.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding and interpretation of a Reliability Standard. A standard reference may support the implementation of a Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.
Guideline	Recommended process that identifies a method of meeting a Requirement under specific conditions.
Supplement	Data forms, pro forma documents, and associated instructions that support the implementation of a Reliability Standard.
Training Material	Documents that support the implementation of a Reliability Standard.
Procedure	Step-wise instructions defining a particular process or operation. Procedures may support the implementation of a Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.
White Paper	An informal paper stating a position or concept. A white paper may be used to propose preliminary concepts for a Reliability Standard or one of the documents above.

[32] The Standards Committee's Procedure for Approving the Posting of Reference Documents is posted on the Reliability Standards Resources web page.

Section 12.0: Process for Correcting Errata

From time to time, an error may be discovered in a Reliability Standard. Such errors may be corrected (i) following a Final Ballot prior to Board of Trustees adoption, (ii) following Board of Trustees adoption prior to filing with Applicable Governmental Authorities; and (iii) following filing with Applicable Governmental Authorities. If the Standards Committee agrees that the correction of the error does not change the scope or intent of the associated Reliability Standard, and agrees that the correction has no material impact on the end users of the Reliability Standard, then the correction shall be filed for approval with Applicable Governmental Authorities as appropriate. The NERC Board of Trustees has resolved to concurrently approve any errata approved by the Standards Committee.

Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards

All Reliability Standards shall be reviewed at least once every ten years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later. If a Reliability Standard is approved by ANSI as an American National Standard, it shall be reviewed at least once every five years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later.

The *Reliability Standards Development Plan* shall include projects that address this five or ten-year review of Reliability Standards.

- If a Reliability Standard is nearing its five or ten-year review and has issues that need resolution, then the *Reliability Standards Development Plan* shall include a project for the complete review and associated revision of that Reliability Standard that includes addressing all outstanding governmental directives, all approved Interpretations, and all unresolved issues identified by stakeholders.
- If a Reliability Standard is nearing its five or ten-year review and there are no outstanding governmental directives, Interpretations, or unresolved stakeholder issues associated with that Reliability Standard, then the Reliability *Standards Development Plan* shall include a project solely for the "five-year review" of that Reliability Standard.

For a project that is focused solely on the five-year review, the Standards Committee shall appoint a review team of subject matter experts to review the Reliability Standard and recommend whether the American National Standard Institute-approved Reliability Standard should be reaffirmed, revised, or withdrawn. Each review team shall post its recommendations for a 45 calendar day formal stakeholder comment period and shall provide those stakeholder comments to the Standards Committee for consideration.

- If a review team recommends reaffirming a Reliability Standard, the Standards Committee shall submit the reaffirmation to the Board of Trustees for adoption and then to Applicable Governmental Authorities for approval. Reaffirmation does not require approval by stakeholder ballot.
- If a review team recommends modifying, or retiring a Reliability Standard, the team shall develop a SAR with such a proposal and the SAR shall be submitted to the Standards Committee for prioritization as a new project. Each existing Reliability Standard recommended for modification, or retirement shall remain in effect in accordance with the associated implementation plan until the action to modify or withdraw the Reliability Standard is approved by its ballot pool, adopted by the Board of Trustees, and approved by Applicable Governmental Authorities.

In the case of reaffirmation of a Reliability Standard, the Reliability Standard shall remain in effect until the next five or ten-year review or until the Reliability Standard is otherwise modified or withdrawn by a separate action.

Section 14.0: Public Access to Reliability Standards Information

14.1: Online Reliability Standards Information System

The NERC Reliability Standards Staff shall maintain an electronic copy of information regarding currently proposed and currently in effect Reliability Standards. This information shall include current Reliability Standards in effect, proposed revisions to Reliability Standards, and proposed new Reliability Standards. This information shall provide a record, for at a minimum the previous five years, of the review and approval process for each Reliability Standard, including public comments received during the development and approval process.

14.2: Archived Reliability Standards Information

The NERC Staff shall maintain a historical record of Reliability Standards information that is no longer maintained online. Archived information shall be retained indefinitely as practical, but in no case less than five years or one complete standard cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC Reliability Standards Staff of a written request.

Section 15.0: Process for Updating Standard Processes

15.1: Requests to Revise the Standard Processes Manual

Any person or entity may submit a request to modify one or more of the processes contained within this manual. The Standards Committee shall oversee the handling of each request. The Standards Committee shall prioritize all requests, merge related requests, and respond to each sponsor within 30 calendar days.

The Standards Committee shall post the proposed revisions for a 45 (calendar) day formal comment period. Based on the degree of consensus for the revisions, the Standards Committee shall:

a. Submit the revised process or processes for ballot pool approval;
b. Repeat the posting for additional inputs after making changes based on comments received;
c. Remand the proposal to the sponsor for further work; or
d. Reject the proposal.

The Registered Ballot Body shall be represented by a ballot pool. The ballot procedure shall be the same as that defined for approval of a Reliability Standard, including the use of an Additional Ballot if needed. If the proposed revision is approved by the ballot pool, the Standards Committee shall submit the revised procedure to the Board for adoption. The Standards Committee shall submit to the Board a description of the basis for the changes, a summary of the comments received, and any minority views expressed in the comment and ballot process. The proposed revisions shall not be effective until approved by the NERC Board of Trustees and Applicable Governmental Authorities.

Section 16.0: Waiver

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC may need to develop a new or modified Reliability Standard, definition, Variance, or implementation plan under specific time constraints (such as to meet a time constrained regulatory directive) or to meet an urgent reliability issue such that there isn't sufficient time to follow all the steps in the normal Reliability Standards development process.

The Standards Committee may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:

- In response to a national emergency declared by the United States or Canadian government that involves the reliability of the Bulk Electric System or cyber attack on the Bulk Electric System;
- Where necessary to meet regulatory deadlines;
- Where necessary to meet deadlines imposed by the NERC Board of Trustees; or
- Where the Standards Committee determines that a modification to a proposed Reliability Standard or its Requirement(s), a modification to a defined term, a modification to an interpretation, or a modification to a variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.

In no circumstances shall this provision be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard.

A waiver request may be submitted to the Standards Committee by any entity or individual, including NERC committees or subgroups and NERC Staff. Prior to consideration of any waiver request, the Standards Committee must provide five business days notice to stakeholders.

Action on the waiver request will be included in the minutes of the Standards Committee. Following the approval of the Standards Committee to waive any provision of the Standard Process Manual, the Standards Committee will report this decision to the Standards Oversight and Technology Committee.[33] Actions taken pursuant to an approved waiver request will be posted on the Standard Project page and included in the next project announcement.

In addition, the Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance.

Reliability Standards developed as a result of a waiver of any provision of the Standard Processes Manual shall not be filed with ANSI for approval as American National Standards.

[33] Any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Proposed Revisions to the Standard Processes Manual

Appendix 3A to the NERC Rules of Procedure
Section 6.0, Processes for Conducting Field Tests | September 2015

Revisions are proposed to Section 6, *Processes for Conducting Field Tests and Collecting and Analyzing Data*, of the NERC Standard Processes Manual (SPM), Appendix 3A to the NERC Rules of Procedure. Under Section 6.0 of the SPM, field tests may be used to analyze data and validate concepts in the development of Reliability Standards. Changes are proposed to develop a more concise process for conducting field tests, to clarify oversight and authority over the technical aspects of field tests, and to increase coordination across the Standards Committee (SC) and the NERC technical committee overseeing the field test when field tests are conducted.

A redline of the proposed changes is available on the Revisions to the NERC SPM page.

The proposed revisions are posted for a 30-day informal comment period from September 29, 2015 through October 28, 2015. All comments should be submitted through the NERC Standards Balloting and Commenting System (SBS).

Background

In March 2015, the SC endorsed developing draft revisions to the SC Charter and Section 6 of the SPM to develop more concise language and provide NERC's technical committees with additional oversight and authority over the technical aspect of field tests associated with Standards Authorization Requests and standards projects.

NERC staff, along with members of the NERC Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee, worked together to develop the proposed revisions.

Summary of Proposed Revisions

The proposed revisions are summarized as follows:

Section 6.1 is revised to streamline the requirements for field tests to validate concepts that support the development of requirements (current Section 6.1) and field tests of technical concepts in a proposed new or revised Reliability Standard (current Section 6.2). Two new subsections are created:

> Proposed Section 6.1.1 summarizes, in bullet form, the requirements for seeking approval of a field test. Under the proposed revisions, the requesting team must first identify a NERC technical committee to lead the effort to conduct the field test and seek approval from that technical committee to conduct the field test before seeking SC approval.

Proposed Section 6.1.2 provides that the lead NERC technical committee overseeing the field test may stop or modify the field test if it determines that the field test activity poses a reliability risk to the Bulk Electric System (BES). Prior to restarting a stopped field test, the requesting team must receive approval from the lead NERC technical committee and the SC in accordance with proposed Section 6.1.1.

Proposed Section 6.2 clarifies the processes governing communication and coordination for all types of field tests. The proposed revisions clarify the process for seeking, approving, and making notifications with respect to compliance waivers for participating entities unable to comply with currently-enforceable Reliability Standards due to their participation in the field test. Proposed Section 6.2 also contains requirements for keeping the NERC Board of Trustees informed of pending and ongoing field tests, including any requested compliance waivers.

Next Steps

NERC staff will consider all comments received during the comment period and determine next steps.

Standard Requirement	OC	PC	RE	NERC	Avg.	OC	PC	RE	NERC	Avg.	Max Dif
	Content Questions					Quality Questions					
BAL-001-2 , R1	3	3	3	3	3.00	12	11	11	12	11.5	**1**
BAL-001-2 , R2	3	3	3	3	3.00	12	11	11	10	11	**2**
EOP-010-1, R1	3	3	3	3	3.00	12	12	12	12	12	**0**
EOP-010-1, R2		3	2	3	2.67	12	12	8	11	10.75	**4**
EOP-010-1, R3.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
EOP-011-1, R1.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
EOP-011-1, R2.	3	3	3	3	3.00	12	12	12	12	12	**0**
EOP-011-1, R3.	3	3	1	3	2.50	12	12	11	10	11.25	**2**
EOP-011-1, R4.	3	3	1	3	2.50	12	12	12	10	11.5	**2**
EOP-011-1, R5.	3	3	2	3	2.75	12	12	11	12	11.75	**1**
EOP-011-1, R6.	3	3	2	3	2.75	12	12	12	10	11.5	**2**
FAC-008-3, R1	3	3	3	3	3.00	12	11	9	9	10.25	**3**
FAC-008-3, R2.		3	3	3	3.00		11	11	12	11.33	**1**
FAC-008-3, R3.	3	3	3	3	3.00	12	11	11	12	11.5	**1**
FAC-008-3, R6.	3	3	3	3	3.00	12	11	10	11	11	**2**
FAC-008-3, R7.	3	3	2	2	2.50	12	11	10	10	10.75	**2**
FAC-008-3, R8.	3	3	3	2	2.75	10	11	10	10	10.25	**1**
INT-004-3.1 , R3.	3	3		3	3.00	12	10	12	11	11.25	**2**
INT-006-4, R1	3	3	3	3	3.00	12	10	11	11	11	**2**
INT-006-4, R2	3	3	3	3	3.00	12	10	11	12	11.25	**2**
INT-006-4, R3.	3	3	3	3	3.00	12	11	11	12	11.5	**1**
INT-006-4, R4	3	3	3	3	3.00	12	11	10	12	11.25	**2**
INT-006-4, R5	3	3	3	3	3.00	12	11	12	12	11.75	**1**
INT-009-2.1, R1	3	3	3	3	3.00	12	12	12	10	11.5	**2**
INT-009-2.1, R2	3	3	3	3	3.00	12	12	12	12	12	**0**
INT-009-2.1, R3.	3	3	3	3	3.00	12	12	12	12	12	**0**
INT-010-2.1, R1	3	3	3	3	3.00	12	8	10	12	10.5	**4**
INT-010-2.1, R2	3	3	3	3	3.00	12	8	12	12	11	**4**
INT-010-2.1, R3.	3	3	3	3	3.00	12	8	12	10	10.5	**4**
NUC-001-3, R1	3	3	3	3	3.00	12	12	12	12	12	**0**
NUC-001-3, R2.	3	3	3	3	3.00	12	12	12	12	12	**0**
NUC-001-3, R3.	3	3	2	3	2.75	12	12	12	12	12	**0**
NUC-001-3, R4.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
NUC-001-3, R5.	3	3	3	3	3.00	12	12	12	12	12	**0**
NUC-001-3, R6.	3	3	3	3	3.00	12	12	12	12	12	**0**

Standard Requirement	OC	PC	RE	NERC	Avg.	OC	PC	RE	NERC	Avg.	Max Dif
	Content Questions					Quality Questions					
NUC-001-3, R7.	3	3	3	3	3.00	12	12	12	12	12	**0**
NUC-001-3, R8.	3	3	3	3	3.00	12	12	12	12	12	**0**
NUC-001-3, R9	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PER-003-1, R1.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
PER-003-1, R2.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
PER-003-1, R3.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
PER-004-2, R1.	3	3	2	3	2.75	12	11	10	12	11.25	**2**
PER-004-2, R2.	3	3		3	3.00	7	7	12	12	9.5	**5**
PRC-004-5(i), R1.	3	3	2	3	2.75	12	12	12	11	11.75	**1**
PRC-004-5(i), R2.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-004-5(i), R3.	3	3	3	3	3.00	12	12	11	10	11.25	**2**
PRC-004-5(i), R4.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-004-5(i), R5.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-004-5(i), R6.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-005-6, R1.	3	3	2	3	2.75	12	12	11	10	11.25	**2**
PRC-005-6, R2.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-005-6, R3.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-005-6, R4.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-005-6, R5.	3	2	3	3	2.75	12	6	12	10	10	**6**
PRC-006-2 , R1.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-006-2 , R2.	2	2	2	2	2.00	12	12	11	11	11.5	**1**
PRC-006-2 , R3.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-006-2 , R4.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-006-2 , R5.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-006-2 , R6.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-006-2 , R7.	3	3	3	3	3.00	12	12	12	12	12	**0**
PRC-006-2 , R8.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-006-2 , R9.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
PRC-006-2 , R10.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-006-2 , R11.	3	3	3	3	3.00	12	12	12	12	12	**0**
PRC-006-2 , R12.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
PRC-006-2 , R13.	3	3	3	3	3.00	12	12	12	12	12	**0**
PRC-010-2, R1.	3	3	1	3	2.50	12	12	12	10	11.5	**2**
PRC-010-2, R2.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
PRC-010-2, R3.	3	3	1	3	2.50	12	12	9	12	11.25	**3**

Standard Requirement	OC	PC	RE	NERC	Avg.	OC	PC	RE	NERC	Avg.	Max Dif
	Content Questions					Quality Questions					
PRC-010-2, R4.	3	3	1	3	2.50	12	12	12	12	12	**0**
PRC-010-2, R5.	3	3	1	3	2.50	12	12	12	12	12	**0**
PRC-010-2, R6.	3	3	3	3	3.00	12	12	12	10	11.5	**2**
PRC-010-2, R7.	3	3	3	3	3.00	12	12	12	12	12	**0**
PRC-010-2, R8.	3	3	3	3	3.00	12	12	12	12	12	**0**
PRC-019-2, R1.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-019-2, R2.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-023-4, R1.	3	3	3	3	3.00	12	12	9	12	11.25	**3**
PRC-023-4, R2.	3	3	2	3	2.75	12	12	9	12	11.25	**3**
PRC-023-4, R3.	3	3	2	3	2.75	12	12	11	12	11.75	**1**
PRC-023-4, R4.	3	3	2	3	2.75	12	12	10	12	11.5	**2**
PRC-023-4, R5.	3	3	3	3	3.00	12	12	11	8	10.75	**4**
PRC-023-4, R6.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-024-2, R1.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-024-2, R2.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-024-2, R3.	3	3	3	3	3.00	12	12	10	12	11.5	**2**
PRC-024-2, R4.	3	3	3	3	3.00	12	12	11	12	11.75	**1**
PRC-025-1, R1.	3	3	2	3	2.75	12	12	10	12	11.5	**2**
VAR-001-4.1, R1.	3	3	3	3	3.00	12	12	10	9	10.75	**3**
VAR-001-4.1, R2.	3	3	3	3	3.00	12	12	11	10	11.25	**2**
VAR-001-4.1, R3.	3	3	3	3	3.00	12	12	11	11	11.5	**1**
VAR-001-4.1, R4.	3	3	3	2	2.75	12	12	9	11	11	**3**
VAR-001-4.1, R5.	3	3	3	3	3.00	12	12	12	11	11.75	**1**
VAR-001-4.1, R6.	3	3	2	3	2.75	12	12	12	11	11.75	**1**
VAR-002-4, R1.	3	3	3	3	3.00	12	12	9	12	11.25	**3**
VAR-002-4, R2.	3	3	3	3	3.00	12	12	12	12	12	**0**
VAR-002-4, R3.	3	3	3	3	3.00	12	12	12	12	12	**0**
VAR-002-4, R4.	3	3	3	3	3.00	12	12	10	12	11.5	**2**
VAR-002-4, R5.	3	3	3	3	3.00	12	12	12	12	12	**0**
VAR-002-4, R6.	3	3	3	3	3.00	12	12	10	11	11.25	**2**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Frequently Asked Questions

Enhanced Periodic Review Standing Review Team – Standards Grading

The following questions and answers are intended to facilitate understanding about the Enhanced Periodic Review Standing Review Team – Standards Grading process. Please contact Mat Bunch (via email) or at (404) 446-9785 with any additional questions you may have.

Enhanced Periodic Review Standing Review Team – Standards Grading process FAQs

Q1: Why are standards being graded?

A1. The Standards Committee (SC), at its March 9, 2016 meeting, endorsed the use of the grading tool used by the Independent Expert Review Panel (IERP) as the metric to grade all NERC Reliability Standards. The Enhanced Periodic Review Standing Team (EPRST), with the SC chair facilitating the meetings, conducted an initial grading of all currently-enforceable Reliability Standards with requirements that have been subject to enforcement in the United States for at least one year. The grading activity is conducted during pre-scheduled public meetings/calls open to stakeholders. The most up-to-date information can be found on the EPR project page.

The EPRST has completed its initial grading, which is posted for a 30-day industry comment period. The EPRST has sought input from stakeholders prior to finalizing the grading. The finalized grading will be appended to the Reliability Standards Development Plan (RSDP), which has been endorsed by the SC.

Q2: Who comprises the Standing Review Team (SRT)?

A2: The chairs of the SC, Operating Committee (OC), Planning Committee (PC), a representative for the Regional Entities, and NERC staff comprise the Enhanced Periodic Review Standing Review Team (EPRSRT). The primary role of the SC chair or the delegate is to facilitate the meetings and not to grade the standards. The SC chair (or the delegate) also assists to resolve differences of opinions.

Q3: What are the grades used for?

A3: The final grade will be an early input to future EPRs, along with additional information collected, as required under the EPR Template. If an EPR team recommends revising standard requirements that were graded in 2016, the SRT will re-grade those standard requirements based on the recommended revision. The re-graded requirements will also be posted for additional stakeholder comment prior to final SRT grading.

Q4. What is the grading tool?

A4. The grading tool is based on the grading tool from the 2013 Standards Independent Experts Review Project. The SC endorsed using the same decisions-tree and grading criteria, with the addition of one quality question on cost effectiveness. For purposes of the 2016 standards grading, the cost-effectiveness quality question does not contribute to the final numeric grade for quality. The grading tool completed by the EPRSRT is available on the project web page.

Q5: What are the eligibility criteria for a standard to be graded?

A5: All requirements of a Reliability Standard must have been in effect, based on the implementation/compliance dates approved by the applicable governmental authority, for at least a year. In some instances, a standard may be eligible if:

- It has been a year since the effective date of the order approving that standard if entities are "early adopting" the requirements as they implement their programs to prepare for the effective date; or
- If the standard is a revision to a standard that has been in effect greater than a year.

For example, in some cases, the EPRSRT is grading a standard that is subject to future enforcement, but that is because it is a revised version of a standard that covers materially the same or similar topics. In the case of an entirely new standard, for example, PRC-026-1 regarding stable power swings, the subject matter has not been directly covered by a previous standard and is not being graded at this time.

Q6: How did the EPRSRT determine the grades that are posted?

A6: Each EPRSRT member used the posted standards grading tool to develop initial grades, which the team discussed at the June 23, 2016 public meeting in Atlanta. The EPRSRT focused its discussions on developing consensus grades on standards where individual grading variances equaled or exceeded one point for content or three points for quality. The EPRSRT requested comments from industry on specific standards grades where the EPRSRT was unable to reach strong consensus or desired specific stakeholder input before finalizing a consensus position. In those instances the EPRSRT believes that additional input from an industry perspective would assist the team's final grading.

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
1	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 82.61% Approval: 80.73%			
2	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 83.01% Approval: 79.89%			
3	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 88.83% Approval: 95.43%			
4	Project 2008-07	Interpretation Request - EOP-002 - Brookfield_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 89.67% Approval: 76.47%			
5	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_rc	Recirculation Ballot	6/13/2008	6/22/2008	Quorum: 89.36% Approval: 95.21%			
6	Project 2008-09	Request for Interpretation - EOP-001-0 - RECM_in	Initial Ballot	6/19/2008	7/2/2008	Quorum: 84.82% Approval: 85.79%			
7	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.57% Approval: 79.13%			
8	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.98% Approval: 78.31%			
9	Pre-2006	IROL Standard - IRO-010_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.71% Approval: 88.40%			
10	Pre-2006	IROL Standard - IRO-009_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.63% Approval: 89.44%			
11	Pre-2006	IROL Standard - IRO-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.67% Approval: 91.71%			
12	Project 2006-07	ATC et al Standard - MOD-030_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.37% Approval: 56.56%			
13	Project 2006-07	ATC et al Standard - MOD-029_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.67% Approval: 92.62%			
14	Project 2006-07	ATC et al Standard - MOD-028_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.64% Approval: 79.47%			
15	Project 2006-07	ATC et al Standard - MOD-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.27% Approval: 80.44%			
16	Project 2006-07	ATC et al Standard - MOD-001_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.02% Approval: 75.97%			
17	Project 2008-10	Request for Interpretation - CIP-006-1 - Progress Energy_in	Initial Ballot	8/7/2008	8/16/2008	Quorum: 88.18% Approval: 21.52%			
18	Pre-2006	IROL Standard - IRO-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.72% Approval: 89.49%			
19	Pre-2006	IROL Standard - IRO-009_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.68% Approval: 86.53%			
20	Pre-2006	IROL Standard - IRO-010_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 85.95%			
21	Project 2006-07	ATC et al Standards - MOD-001_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 94.87% Approval: 76.83%			
22	Project 2006-07	ATC et al Standard - MOD-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.15% Approval: 81.49%			
23	Project 2006-07	ATC et al Standard - MOD-028_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.54% Approval: 79.34%			
24	Project 2006-07	ATC et al Standard - MOD-029_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.56% Approval: 92.24%			
25	Project 2006-07	ATC et al Standard - MOD-030_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.24% Approval: 74.26%			
26	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_in	Initial Ballot	9/9/2008	9/17/2008	Quorum: 85.78% Approval: 90.37%			
27	Project 2006-07	ATC et al Standard - MOD-004_in	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.26% Approval: 66.29%			
28	Project 2007-14	Permanent Changes to CI Timing Tables_in	Initial Ballot	9/12/2008	9/22/2008	Quorum: 79.74% Approval: 100.00%			
29	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rb	Re-ballot	10/6/2008	10/24/2008	Quorum: 82.61% Approval: 74.67%			
30	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_in	Initial Ballot	10/21/2008	10/30/2008	Quorum: 83.33% Approval: 96.94%			
31	Project 2006-01	Project 2006-01 - PER-005-1_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 90.13% Approval: 82.47%			
32	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 89.13% Approval: 70.01%			
33	Project 2006-07	ATC et al Standard - MOD-004_rc	Recirculation Ballot	10/28/2008	11/6/2008	Quorum: 91.49% Approval: 83.71%			

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34	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_in	Initial Ballot	12/1/2008	12/10/2008	Quorum: 83.77% Approval: 86.51%			
35	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 93.04% Approval: 57.37%			
36	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 87.62% Approval: 97.47%			
37	Project 2006-01	Project 2006-01 - PER-005-1_rc	Recirculation Ballot	12/12/2008	12/22/2008	Quorum: 91.48% Approval: 80.63%			
38	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.15% Approval: 97.39%			
39	Project 2008-16	TOP-004-2 VSL Revisions_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.20% Approval: 93.93%			
40	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_rc	Recirculation Ballot	1/6/2009	1/15/2009	Quorum: 91.47% Approval: 91.21%			
41	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_rc	Recirculation Ballot	1/20/2009	1/29/2009	Quorum: 85.86% Approval: 86.39%			
42	Project 2008-16	TOP-004-2 VSL Revisions_rc	Recirculation Ballot	1/28/2009	2/6/2009	Quorum: 92.59% Approval: 96.06%			
43	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_rc	Recirculation Ballot	2/6/2009	2/16/2009	Quorum: 93.81% Approval: 99.12%			
44	Project 2008-09	Interpretation Request - EOP-001 - R1 - RECM_in	Initial Ballot	2/27/2009	3/9/2009	Quorum: 89.67% Approval: 89.03%			
45	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_in	Initial Ballot	3/19/2009	3/30/2009	Quorum: 89.78% Approval: 92.62%			
46	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_in	Initial Ballot	4/1/2009	4/10/2009	Quorum: 91.90% Approval: 84.06%			
47	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_in	Initial Ballot	4/8/2009	4/17/2009	Quorum: 92.70% Approval: 92.71%			
48	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_in	Initial Ballot	4/14/2009	4/23/2009	Quorum: 89.81% Approval: 76.63%			
49	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 94.37% Approval: 88.32%			
50	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 95.56% Approval: 92.81%			
51	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_in	Initial Ballot	4/22/2009	5/1/2009	Quorum: 88.64% Approval: 84.77%			
52	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_rc	Recirculation Ballot	5/6/2009	5/18/2009	Quorum: 92.08% Approval: 75.39%			
53	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_in	initial Ballot	5/25/2009	6/4/2009	Quorum: 85.13% Approval: 82.10%			
54	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_rc	Recirculation Ballot	5/26/2009	6/5/2009	Quorum: 90.45% Approval: 85.76%			
55	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_in	Initial Ballot	6/1/2009	6/11/2009	Quorum: 87.10% Approval: 95.71%			
56	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_in	Initial Ballot	6/12/2009	6/22/2009	Quorum: 81.72% Approval: 94.09%			
57	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_in	Initial Ballot	6/15/2009	6/24/2009	Quorum: 87.23% Approval: 83.94%			
58	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_rc	Recirculation Ballot	7/7/2009	7/16/2009	Quorum: 92.77% Approval: 84.96%			
59	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_rc	Recirculation Ballot	7/8/2009	7/17/2009	Quorum: 90.26% Approval: 82.25%			
60	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_rc	Recirculation Ballot	7/10/2009	7/20/2009	Quorum: 87.10% Approval: 96.94%			
61	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 95.26% Approval: 95.62%			
62	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 91.24% Approval: 98.85%			
63	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 90.46%			
64	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.40% Approval: 89.14%			
65	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.32% Approval: 88.26%			
66	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.16% Approval: 90.15%			

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67	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 88.63%			
68	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.64% Approval: 87.63%			
69	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.50% Approval: 85.78%			
70	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.28% Approval: 89.56%			
71	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 87.98% Approval: 87.31%			
72	Project 2009-17	Project 2009-17 Interpretation - Y-W Electric and Tri-State - PRC-004-1 and PRC-005-1_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 90.32% Approval: 62.15%			
73	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rb	Re-ballot	7/27/2009	8/14/2009	Quorum: 84.65% Approval: 74.79%			
74	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_in	Initial Ballot	8/6/2009	8/17/2009	Quorum: 84.68% Approval: 68.92%			
75	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 89.28%			
76	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.04% Approval: 89.41%			
77	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.41% Approval: 84.64%			
78	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.67% Approval: 88.04%			
79	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.17% Approval: 88.73%			
80	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 90.77%			
81	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.31% Approval: 86.93%			
82	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.11% Approval: 88.26%			
83	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.70% Approval: 85.80%			
84	Order 706-B	Order 706-B Nuclear Implementation Plan_in	Initial Ballot	8/19/2009	8/28/2009	Quorum: 81.96% Approval: 97.37%			
85	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rc	Recirculation Ballot	8/20/2009	8/31/2009	Quorum: 86.96% Approval: 70.85%			
86	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.68% Approval: 80.37%			
87	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.92% Approval: 79.04%			
88	Project 2009-18	Project 2009-18 - Withdraw Three Midwest ISO Waivers_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 85.28% Approval: 99.62%			
89	Order 706-B	Order 706-B Nuclear Implementation Plan_rc	Recirculation Ballot	9/1/2009	9/10/2009	Quorum: 87.11% Approval: 97.18%			
90	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rc	Recirculation Ballot	9/2/2009	9/14/2009	Quorum: 86.31% Approval: 76.09%			
91	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_in	Initial Ballot	9/10/2009	9/21/2009	Quorum: 87.45% Approval: 94.18%			
92	Project 2009-16	Project 2009-16 - Interpretation - WECC - CIP-007-1_in	Initial Ballot	9/9/2009	9/21/2009	Quorum: 85.31% Approval: 100.00%			
93	Project 2006-04	Project 2006-04 - Back-up Facilities - EOP-008-1_in	Initial Ballot	9/16/2009	9/28/2009	Quorum: 82.69% Approval: 72.86%			
94	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_rc	Recirculation Ballot	9/29/2009	10/9/2009	Quorum: 89.92% Approval: 68.31%			
95	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 Revised R1 for Progress Energy	Initial Ballot	9/30/2009	10/12/2009	Quorum: 79.92% Approval: 74.47%			
96	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_rc	Recirculation Ballot	10/16/2009	10/26/2009	Quorum: 86.29% Approval: 83.25%			
97	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_rc	Recirculation Ballot	11/2/2009	11/12/2009	Quorum: 88.70% Approval: 94.24%			
98	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 2_in	Initial Ballot	11/5/2009	11/16/2009	Quorum: 85.97% Approval: 98.07%			
99	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_in	Initial Ballot	11/20/2009	11/30/2009	Quorum: 89.58% Approval: 88.07%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
100	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 1)_in	Initial Ballot	11/19/2009	12/7/2009	Quorum: 85.83% Approval: 58.91%			
101	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._in	Initial Ballot	11/20/2009	12/7/2009	Quorum: 87.11% Approval: 93.40%			
102	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_rc	Recirculation Ballot	12/3/2009	12/14/2009	Quorum: 93.33% Approval: 85.55%			
103	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers_in	Initial Ballot	12/1/2009	12/14/2009	Quorum: 86.13% Approval: 72.11%			
104	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_rc	Recirculation Ballot	12/11/2009	12/23/2009	Quorum: 90.08% Approval: 78.77%			
105	Project 2009-24	Project 2009-24 - Interpretation - FMPA - EOP-005-1_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 87.68% Approval: 17.79%			
106	Project 2009-25	Project 2009-25 - Interpretation - BPA - BAL-001-01.a and BAL-002-0_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 88.00% Approval: 34.28%			
107	Project 2009-26	Project 2009-26 - Interpretation - WECC - CIP-004-1_in	Initial Ballot	1/6/2010	1/19/2010	Quorum: 84.21% Approval: 42.24%			
108	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Initial Ballot	1/12/2010	1/22/2010	Quorum: 89.16% Approval: 75.16%			
109	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 84.98% Approval: 90.82%			
110	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 87.36% Approval: 91.79%			
111	Project 2009-29	Project 2009-29 - Interpretation - TOP-002-2a for FMPP_in	Initial Ballot	2/11/2010	2/22/2010	Quorum: 84.34% Approval: 84.56%			
112	Project 2009-19	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.83% Approval: 48.60%			
113	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._rc	Recirculation Ballot	2/16/2010	2/26/2010	Quorum: 92.44% Approval: 91.90%			
114	Project 2009-30	Project 2009-30 - Interpretation - PRC-001-1 for WPSC_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.51% Approval: 48.74%			
115	Project 2006-02	Project 2006-02 - Assess Transmission Future Needs - TPL-001-1_in	Initial Ballot	2/19/2010	3/1/2010	Quorum: 91.38% Approval: 35.36%			
116	Project 2009-31	Project 2009-31 - Interpretation - TOP-001-1 for FMPP_in	Initial Ballot	3/3/2010	3/16/2010	Quorum: 88.24% Approval: 98.27%			
117	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Recirculation Ballot	3/8/2010	3/18/2010	Quorum: 93.71% Approval: 78.15%			
118	Project 2009-32	Project 2009-32 - Interpretation - EOP-003-1 for FMPP_rb	Re-ballot	3/10/2010	3/31/2010	Quorum: 91.37% Approval: 77.66%			
119	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers (Revision 1)_in	Initial Ballot	3/29/2010	4/8/2010	Quorum: 88.52% Approval: 63.43%			
120	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_in	Initial Ballot	4/15/2010	4/26/2010	Quorum: 81.97% Approval: 98.64%			
121	SPM	Standards Process Manual Revisions_in	Initial Ballot	4/19/2010	4/29/2010	Quorum: 87.82% Approval: 80.48%			
122	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_in	Initial Ballot	4/28/2010	5/10/2010	Quorum: 83.15% Approval: 74.55%			
123	SPM	Standards Process Manual Revisions_rc	Recirculation Ballot	4/30/2010	5/10/2010	Quorum: 93.73% Approval: 86.69%			
124	Project 2010-11	Project 2010-11 SAR for TPL Table 1 Order_in	Initial Ballot	5/17/2010	5/27/2010	Quorum: 84.41% Approval: 63.75%			
125	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_in	Initial Ballot	5/19/2010	6/1/2010	Quorum: 84.83% Approval: 90.83%			
126	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_rc	Recirculation Ballot	6/22/2010	7/2/2010	Quorum: 89.10% Approval: 87.24%			
127	Project 2006-04	Project 2006-04 - Backup Facilities - Revision 1_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 89.05% Approval: 79.45%			
128	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 87.04% Approval: 84.98%			
129	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Initial Ballot	7/7/2010	7/17/2010	Quorum: 86.94% Approval: 43.13%			
130	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Initial Ballot	7/8/2010	7/17/2010	Quorum:91.12 % Approval: 22.91%			
131	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	7/8/2010	7/17/2010	Quorum: 86.00% Approval: 28.00%			
132	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: Protection System definition	Initial Ballot	7/8/2010	7/17/2010	Quorum: 87.85% Approval: 39.35%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
133	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Initial Ballot	7/9/2010	7/19/2010	Quorum: 86.18% Approval: 65.93%			
134	Project 2006-04	Prokect 2006-04 - Backup Facilities - Revision 1_rc	Recirculation Ballot	7/16/2010	7/26/2010	Quorum: 93.43% Approval: 85.22%			
135	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	7/23/2010	8/2/2010	Quorum: 94.70% Approval: 58.61%			
136	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	7/24/2010	8/3/2010	Quorum: 92.99% Approval: 49.61%			
137	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_rc	Recirculation Ballot	8/20/2010	8/30/2010	Quorum: 88.26% Approval: 93.93%			
138	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Initial Ballot	9/14/2010	9/24/2010	Quorum: 92.73% Approval: 79.17%			
139	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Initial Ballot	9/17/2010	9/27/2010	Quorum: 96.46% Approval: 21.77%			
140	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	9/24/2010	10/4/2010	Quorum: 85.71% Approval: 81.72%			
141	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	10/2/2010	10/14/2010	Quorum: 84.11% Approval: 84.52%			
142	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_rc	Recirculation Ballot	10/4/2010	10/14/2010	Quorum: 88.11% Approval: 99.14%			
143	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_rc	Recirculation Ballot	10/5/2010	10/15/2010	Quorum: 92.19% Approval: 94.78%			
144	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_rc	Recirculation Ballot	10/6/2010	10/16/2010	Quorum: 91.21% Approval: 93.44%			
145	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Recirculation Ballot	10/18/2010	10/28/2010	Quorum: 89.84% Approval: 84.67%			
146	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 93.66% Approval: 43.33%			
147	Project 2010-10	Project 2010-10 FAC-013-2 Planning Transfer Capability_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 88.54% Approval: 39.85%			
148	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_in	Initial Ballot	10/28/2010	11/7/2010	Quorum: 81.61% Approval: 93.72%			
149	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Recirculation Ballot	11/1/2010	11/11/2010	Quorum: 89.41% Approval: 86.83%			
150	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_rc	Recirculation Ballot	11/9/2010	11/13/2010	Quorum: 87.00% Approval: 92.88%			
151	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_rc	Recirculation Ballot	11/19/2010	12/3/2010	Quorum: 87.81% Approval: 82.41%			
152	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_in	Initial Ballot	12/1/2010	12/10/2010	Quorum: 87.07% Approval: 77.06%			
153	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-3	Initial Ballot	12/2/2010	12/11/2010	Quorum: 84.46% Approval: 42.89%			
154	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Recirculation Ballot	12/2/2010	12/13/2010	Quorum: 95.50% Approval: 86.91%			
155	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Initial Ballot	12/7/2010	12/16/2010	Quorum: 88.00% Approval: 51.51%			
156	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Successive Ballot	12/10/2010	12/20/2010	Quorum: 79.88% Approval: 44.65%			
157	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	12/10/2010	12/20/2010	Quorum: 78.00% Approval: 53.00%			
158	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_rc	Recirculation Ballot	12/20/2010	12/30/2010	Quorum: 90.49% Approval: 80.56%			
159	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_in	Recirculation Ballot	12/27/2010	1/5/2011	Quorum: 90.42% Approval: 83.33%			
160	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 22.09%	Oppose 12/16/11		
161	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 33.49%	Oppose 12/16/11		
162	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 26.82%	Oppose 12/16/11		
163	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 28.04%	Oppose 12/16/11		
164	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.60%	Oppose 12/16/11		
165	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 24.15%	Oppose 12/16/11		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
166	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 94.02% Approval: 34.30%	Oppose 12/16/11		
167	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 27.28%	Oppose 12/16/11		
168	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 26.61%	Oppose 12/16/11		
169	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.88%	Oppose 12/16/11		
170	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.15% Approval: 42.06%	Oppose 12/16/11		
171	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.56% Approval: 25.34%	Oppose 12/16/11		
172	Project 2010-10	Project 2010-10: FAC Order 729_in	Initial Ballot	12/30/2010	1/8/2011	Quorum: 83.23% Approval: 58.16%			
173	Project 2010-10	Project 2010-10: FAC Order 729_rc	Recirculation Ballot	1/14/2011	1/23/2011	Quorum: 86.65% Approval: 68.98%			
174	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_rc	Recirculation Ballot	1/26/2011	2/5/2011	Quorum: 93.29% Approval: 86.79%	Support 1/5/11		
175	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Successive Ballot	1/24/2011	2/14/2011	Quorum: 83.95% Approval: 65.71%	Support 2/11/11		
176	Project 2007-23	Project 2007-23 - Violation Severity Levels	Non-binding Poll	2/9/2011	2/22/2011	Quorum: 78.00% Approval: 72.00%	Support 10/28/10		
177	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Successive Ballot	2/18/2011	2/28/2011	Quorum: 79.28% Approval: 79.34%	Support 2/22/11		
178	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Recirculation Ballot	2/24/2011	3/6/2011	Quorum: 87.35% Approval: 68.83%	Support 2/11/11		
179	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Initial Ballot	2/25/2011	3/7/2011	Quorum: 87.10% Approval: 49.54%	Support 3/2/11		
180	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-4	Successive Ballot	4/19/2011	4/28/2011	Quorum: 79.66% Approval: 38.00%	Oppose 4/19/11		
181	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Initial Ballot	4/21/2011	5/2/2011	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11		
182	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Non-binding Poll	4/21/2011	5/2/2011	Quorum: 75.58% Approval: 73.00%			
183	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Successive Ballot	5/3/2011	5/12/2011	Quorum: 78.33% Approval: 67.00%	No Recommendation		
184	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	5/3/2011	5/12/2011	Quorum: 75.00% Approval: 66.00%			
185	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Recirculation Ballot	5/12/2011	5/23/2011	Quorum: 91.25% Approval: 78.92%	Support 5/12/11		
186	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot	5/18/2011	5/31/2011	Quorum: 92.07% Approval: 73.99%			
187	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Non-binding Poll	5/18/2011	5/31/2011	Quorum: 86.79% Approval: 71.9%			
188	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Initial Ballot	5/31/2011	6/9/2011	Quorum: 88.47% Approval: 48.64%	Oppose 5/31/11		
189	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Non-binding Poll	5/31/2011	6/9/2011	Quorum: 84.18% Approval: 41.00%			
190	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot	6/20/2011	6/30/2011	Quorum: 82.97% Approval: 64.76%	Support 6/28/11		
191	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Non-binding Poll	6/20/2011	6/30/2011	Quorum: 52.63% Approval: 60.00%			
192	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	Recirculation Ballot	7/13/2011	7/22/2011	Quorum: 94.33% Approval: 75.37%			
193	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.99%	Support 7/22/11		
194	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 75.17%	Support 7/22/11		
195	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.27%	Support 7/22/11		
196	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 93.00%			
197	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.66% Approval: 93.00%			
198	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 89.00%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
199	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.25% Approval: 46.53%	No Consensus 7/28/11		
200	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.75% Approval: 56.00%			
201	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.82% Approval: 18.23%	No Consensus 7/28/11		
202	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.35% Approval: 20.79%			
203	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Initial Ballot	9/19/2011	9/29/2011	Quorum: 84.86% Approval: 61.10%	Support 9/21/11		
204	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	9/19/2011	9/29/2011	Quorum: 83.13% Approval: 68.68%			
205	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Definition of BES	Initial Ballot	9/30/2011	10/10/2011	Quorum: 92.97% Approval: 71.68%	No Consensus 10/3/11		
206	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Initial Ballot	9/30/2011	10/10/2011	Quorum: 89.53% Approval: 64.03%	No Consensus 10/7/111		
207	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Recirculation Ballot	10/4/2011	10/13/2011	Quorum: 87.17% Approval: 86.25%	Support 2/22/11		
208	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Initial Ballot	11/7/2011	11/16/2011	Quorum: 88.05% Approval: 85.53%	Support 11/8/11		
209	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Initial Ballot	11/8/2011	11/17/2011	Quorum: 91.20% Approval: 95.05%	Support 11/8/11		
210	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 88.22% Approval: 86.94%	Support 11/10/11		
211	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Initial Ballot	11/9/2011	11/18/2011	Quorum: 85.08% Approval: 85.71%	Support 11/10/11		
212	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.82% Approval: 85.31%	Support 11/10/11		
213	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.29% Approval: 96.09%	Support 11/10/11		
214	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Successive Ballot	11/11/2011	11/21/2011	Quorum: 83.53% Approval: 95.99%	Support 11/14/11		
215	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System and Implementation Plan	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 95.92% Approval: 81.32%	Support 10/3/11		
216	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 93.02% Approval: 81.48%	Support 10/3/11		
217	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Initial Ballot	11/30/2011	12/9/2011	Quorum: 93.92% Approval: 30.82%	Oppose 12/5/11		
218	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Non-binding Poll	11/30/2011	12/9/2011	Quorum: 89.49% Approval: 36.00%			
219	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Initial Ballot	12/2/2011	12/12/2011	Quorum: 87.97% Approval: 36.21%	Oppose 12/5/11		
220	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	12/2/2011	12/12/2011	Quorum: 85.28% Approval: 45.00%			
221	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Recirculation Ballot	12/9/2011	12/19/2011	Quorum: 88.02% Approval: 96.04%	Support 11/14/11		
222	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Recirculation Ballot	12/12/2011	12/22/2011	Quorum: 90.10% Approval: 92.49%	Support 11/8/11		
223	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 92.00% Approval: 94.58%	Support 11/8/11		
224	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 88.48% Approval: 90.10%	Support 11/10/11		
225	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 87.17% Approval: 85.38%	Support 11/10/11		
226	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.91% Approval: 85.03%	Support 11/10/11		
227	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1a	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.65% Approval: 96.43%	Support 11/10/11		
228	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 59.93%	Oppose 1/9/12		
229	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 77.08 %	Support 1/9/12		
230	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 78.95%	Support 1/9/12		
231	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Non-binding Poll	1/4/2012	1/13/2012	Quorum: 78.27% Approval: 93.00%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
232	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Non-binding Poll	1/9/2012	1/18/2012	Quorum: 76.41% Approval: 71.42%			
233	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 67.61%			
234	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 70.28%			
235	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 54.64%	Oppose 2/7/12		
236	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 82.11% Approval: 80.62%	Support 2/7/12		
237	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 80.21%	Support 2/7/12		
238	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.35% Approval: 71.35%			
239	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.06% Approval: 90.86%			
240	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 79.77% Approval: 84.69%			
241	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Successive Ballot	3/14/2012	3/23/2012	Quorum: 88.55% Approval: 79.61%	Support 3/16/12		
242	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Initial Ballot	3/14/2012	3/23/2012	Quorum: 89.63% Approval: 94.71%	Support 3/16/12		
243	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation	Initial Ballot	3/14/2012	3/23/2012	Quorum: 86.92% Approval: 63.09%	Support 3/16/12		
244	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 81.45% Approval: 61.21%			
245	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 80.38% Approval: 41.09%			
246	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	3/19/2012	3/29/2012	Quorum: 84.32% Approval: 73.93%	Support 3/19/12		
247	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	3/19/2012	3/29/2012	Quorum: 81.93% Approval: 66.12%			
248	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.37% Approval: 85.18%	Support 4/5/12		
249	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.10% Approval: 85.01%	Support 4/5/12		
250	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.28% Approval: 41.09%	Oppose 4/16/12		
251	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 36.84%	Oppose 4/16/12		
252	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 48.70%%	Oppose 4/16/12		
253	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.82% Approval: 43.72%			
254	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.04% Approval: 38.56%			
255	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.53% Approval: 46.38%			
256	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1a	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.95% Approval: 92.41%	Support 4/16/12		
257	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28%% Approval: 75.44%			
258	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.02% Approval: 87.22%			
259	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28% Approval: 80.11%			
260	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.21% Approval: 69.84%			
261	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.48% Approval: 67.64%			
262	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 90.96% Approval: 80.08%	Support 3/16/12		
263	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 92.68% Approval: 94.61%	Support 3/16/12		
264	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.72% Approval: 87.34%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
265	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.94% Approval: 87.32%			
266	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1b	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 90.44% Approval: 93.23%			
267	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 76.84%	Abstain 4/19/12		
268	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 88.11%	Support 4/19/12		
269	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 80.79%	Support 4/19/12		
270	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.63% Approval: 37.37%	Abstain 5/17/12		
271	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.45% Approval: 60.55%	Abstain 5/17/12		
272	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.40% Approval: 38.81%	Abstain 5/17/12		
273	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.98% Approval: 55.08%	Abstain 5/17/12		
274	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.22% Approval: 38.50%	Abstain 5/17/12		
275	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 45.78%	Abstain 5/17/12		
276	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.19% Approval: 67.19%	Abstain 5/17/12		
277	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 60.19%	Abstain 5/17/12		
278	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 47.92%	Abstain 5/17/12		
279	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 58.23%	Abstain 5/17/12		
280	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	5/11/2012	5/21/2012	Quorum: 85.12% Approval: 66.23%	Abstain 5/17/12		
281	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	5/11/2012	5/21/2012	Quorum: 84.09% Approval: 47.88%	Abstain 5/17/12		
282	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	5/15/2012	5/24/2012	Quorum: 84.43% Approval: 46.18%			
283	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	5/15/2012	5/24/2012	Quorum: 79.95% Approval: 52.67%			
284	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Initial Ballot	6/11/2012	6/20/2012	Quorum: 84.14% Approval: 21.11%	Oppose 6/13/12		
285	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	6/11/2012	6/20/2012	Quorum: 81.01% Approval: 28.30%			
286	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	6/18/2012	6/27/2012	Quorum: 79.46% Approval: 79.00%			
287	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	6/18/2012	6/27/2012	Quorum: 75.00% Approval: 70.21%			
288	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Successive Ballot	6/18/2012	6/27/2012	Quorum: 85.98% Approval: 68.22%	Support 6/26/12		
289	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Initial Ballot	6/26/2012	7/5/2012	Quorum: 84.24% Approval: 23.82%	Oppose 6/27/12		
290	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	6/26/2012	7/5/2012	Quorum: 82.26% Approval: 25.19%			
291	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.34% Approval: 81.71%			
292	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.04% Approval: 81.72%			
293	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 84.16% Approval: 79.16%			
294	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 83.87% Approval: 86.91%			
295	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2012	7/9/2012	Quorum: 75.37% Approval: 72.16%	No Consensus 7/5/12		
296	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	6/27/2012	7/11/2012	Quorum: 75.37% Approval: 73.71%			
297	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	7/18/2012	7/27/2012	Quorum: 90.97% Approval: 69.81%	Support 6/26/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
298	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Non-binding Poll	7/18/2012	7/27/2012	Quorum: 81.31% Approval: 60.93%			
299	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	7/20/2012	7/30/2012	Quorum: 80.39% Approval: 79.28%	Oppose 7/20/12		
300	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Non-binding Poll	7/20/2012	7/30/2012	Quorum: 78.26% Approval: 76.07%			
301	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	7/24/2012	8/2/2012	Quorum: 83.11% Approval: 54.16%	Oppose 7/20/12		
302	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	8/17/2012	8/27/2012	Quorum: 78.11% Approval: 80.31%	Support 6/22/12		
303	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	8/23/2012	9/4/2012	Quorum: 79.21% Approval: 87.78%	Support 2/22/10		
304	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Initial Ballot	8/29/2012	9/7/2012	Quorum: 86.71% Approval: 37.68%	Support 9/5/12		
305	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	8/29/2012	9/7/2012	Quorum: 84.17% Approval: 37.36%			
306	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Recirculation Ballot	9/6/2012	9/17/2012	Quorum: 80.35% Approval: 75.01%			
307	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot	9/11/2012	9/20/2012	Quorum: 77.70% Approval: 50.57%	Support 9/15/12		
308	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	9/11/2012	9/20/2012	Quorum: 84.05% Approval: 54.07%			
309	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	9/12/2012	9/21/2012	Quorum: 85.36% Approval: 87.34%			
310	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	9/18/2012	9/27/2012	Quorum: 78.54% Approval: 63.40%	No Consensus 9/27/12		
311	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	9/18/2012	9/27/2012	Quorum: 78.93% Approval: 71.04%			
312	Project 2009-19	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	9/28/2012	10/8/2012	Quorum: 85.11% Approval: 90.34%	Support 2/22/10		
313	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 74.85%	Support 10/4/12		
314	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.37% Approval: 89.50%	Support 10/4/12		
315	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 85.58%	Support 10/4/12		
316	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 89.46%	Support 10/4/12		
317	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.11%	Support 10/4/12		
318	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 87.73%	Support 10/4/12		
319	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.74%	Support 10/4/12		
320	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.73%	Support 10/4/12		
321	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 84.60%	Support 10/4/12		
322	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.90%	Support 10/4/12		
323	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	10/1/2012	10/10/2012	Quorum: 78.93% Approval: 94.00%	Support 10/4/12		
324	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	10/1/2012	10/10/2012	Quorum: 79.13% Approval: 91.59%	Support 10/4/12		
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
331	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.34% Approval: 71.53%			
332	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.07% Approval: 70.64%			
333	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.88% Approval: 77.10%			
334	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.40% Approval: 52.72%			
335	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 77.94% Approval: 64.24%			
336	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.06% Approval: 68.93%			
337	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.51% Approval: 63.63%			
338	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 78.59%	Support 10/4/12		
339	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 92.75%	Support 10/4/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 89.73%	Support 10/4/12		
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 93.73%	Support 10/4/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.53%	Support 10/4/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 91.79%	Support 10/4/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.47%	Support 10/4/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 94.60%	Support 10/4/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 88.99%	Support 10/4/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.67%	Support 10/4/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation Plan	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 94.91%	Support 10/4/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 93.23%	Support 10/4/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Recirculation Ballot	10/24/2012	11/5/2012	Quorum: 85.14% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		
353	Project 2010-11	Project 2010-11 TPL footnote b Initial Ballot October 2012 in	Initial Ballot	11/9/2012	11/19/2012	Quorum: 80.45% Approval: 56.18%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/5/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/5/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 75.77% Approval: 96.45%	Support 12/10/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	12/4/2012	12/13/2012	Quorum: 76.78% Approval: 53.57%	No Consensus 12/13/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	12/4/2012	12/13/2012	Quorum: 77.22% Approval: 57.91%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Successive Ballot	12/7/2012	12/17/2012	Quorum: 76.47% Approval: 33.23%	Oppose 12/17/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	12/7/2012	12/17/2012	Quorum: 75.58% Approval: 34.80%			
360	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Initial Ballot	12/11/2012	12/20/2012	Quorum: 84.50% Approval: 95.60%	Support 12/19/12		
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
364	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012_in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1_- Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
371	Project 2010-14.1	Project 2010-14.1_- Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 82.23% Approval: 24.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.60% Approval: 95.22%	Support 12/10/12		
373	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 87.13% Approval: 99.09%	Support 12/19/12		
374	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.90% Approval: 85.57%	Support 12/19/12		
375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013_in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards
383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.58% Approval: 97.18%	Support 3/14/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.52% Approval: 98.89%	Support 3/14/13		
385	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 81.33% Approval: 89.44%	Support 1/11/13		

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386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard-NPCC will submit suggested improvements

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390	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 23.84%	Oppose 4/23/13		Losses of large blocks of load are typically caused by coincident transmission contingencies. Excessive and uninformed adjustments made to generation in order to bring the ACE to zero may well lead to further transmission issues. NPCC will submit suggested improvements
391	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
392	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Recirculation Ballot	4/18/2013	4/29/2013	Quorum: 80.70% Approval: 88.15%	No Consensus 3/22/13		
395	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Successive ballot	5/15/2013	5/24/2013	Quorum: 81.25% Approval: 69.23%	Support 5/23/13		The Regional Standard Committee has not expressed any concerns of significance that would warrant a ballot to reject, therefore the RSC recommends a yes vote, "Affirmative", to accept the standard
396	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Non-binding Poll	5/15/2013	5/24/2013	Quorum: 80.17% Approval: 61.11%			
397	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	6/24/2013	7/3/2013	Quorum: 77.65% Approval: 52.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	6/24/2013	7/3/2013	Quorum: 77.12% Approval: 52.48%			
399	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Initial Ballot	7/3/2013	7/12/2013	Quorum: 85.53% Approval: 49.73%			
400	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Successive Ballot	7/10/2013	7/19/2013	Quorum: 76.32% Approval: 58.36%	No Consensus 7/19/13 [Due to the concerns expressed over the potential actions by the NERC BOT and FERC as well as the incremental improvement of the standard over the previous versions, NPCC as the Regional Entity will support the standard and submit comments.]		organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren't approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the "final" (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			

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402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over "hitting limits" more frequently and potential issues with BA's potentially "dragging" on the interconnection. NPCC will be voting affirmative on the standard.
405	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Initial Ballot	7/26/2013	8/5/2013	Quorum: 80.05% Approval: 93.00%	Support 8/5/13		
408	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025-1	Final Ballot	8/2/2013	8/12/2013	Quorum: 89.13% Approval: 76.52%	Support 8/12/13		
406	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Initial Ballot	8/2/2013	8/12/2013	Quorum: 76.32% Approval: 62.74%	Support 8/9/13		
407	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	8/2/2013	8/12/2013	Quorum: 75.89% Approval: 55.45%			
409	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Initial Ballot	8/14/2013	8/23/2013	Quorum: 78.33% Approval: 79.42%	Support 8/23/13		
410	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Non-binding Poll	8/14/2013	8/23/2013	Quorum: 77.45% Approval: 81.37%			
411	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Ballot	8/16/2013	8/26/2013	Quorum: 76.14% Approval: 51.10%	No Consensus 8/26/13		NPCC to support with comments
412	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Non-binding Poll	8/16/2013	8/26/2013	Quorum: 75.98% Approval: 53.29%			
413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	8/23/2013	9/3/2013	Quorum: 75.25% Approval: 34.46%	No Consensus 8/31/13		NPCC to support with comments The most contentious issues raised by RSC members was surrounding the Control Center definition and the potential to vastly expand those needing training subject to the standard and compliance and that there was no need for a standard, rather, the FERC Directives should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 80.45% Approval: 34.24%			

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415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	8/23/2013	9/3/2013	Quorum: 81.89% Approval: 43.79%	Oppose 8/31/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, lacks clarity, missing measures, quality, and other substantive issues. NPCC will be submitting detailed comments to address these issues. The RSC does not believe it would be beneficial to support the standard at this point as the next step, if it fails the initial ballot, would still require an additional ballot prior to moving to recirculation due to the substantive changes that are needed for the next revision. NPCC will be submitting helpful comments to NERC and supporting the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 79.95% Approval: 44.23%			
417	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Ballot	8/26/2013	9/4/2013	Quorum: 82.29% Approval: 41.24%	Support 8/31/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 79.66% Approval: 40.00%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Ballot	8/26/2013	9/4/2013	Quorum: 81.96% Approval: 55.76%	Support 8/31/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 80.35% Approval: 58.97%			
421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	8/26/2013	9/4/2013	Quorum: 78.68% Approval: 66.11%	Support 8/31/13		
426	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Final Ballot	9/4/2013	9/13/2013	Quorum: 85.93% Approval: 90.83%	Support 8/5/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Ballot	9/6/2013	9/16/2013	Quorum: 76.15% Approval: 58.23%	No Consensus 9/12/13		
423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Non-binding Poll	9/6/2013	9/16/2013	Quorum: 75.69% Approval: 59.66%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Final Ballot	9/11/2013	9/20/2013	Quorum: 91.64% Approval: 98.61%	Support 3/14/13		
425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Final Ballot	9/11/2013	9/20/2013	Quorum: 90.98% Approval: 98.92%	Support 3/14/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.58% Approval: 88.75%	Support 10/16/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 75.89% Approval: 90.04%			
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Final Ballot	10/16/2013	10/25/2013	Quorum: 85.71% Approval: 85.38%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	10/18/2013	10/29/2013	Quorum: 75.83% Approval: 72.55%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	10/25/2013	11/4/2013	Quorum: 86.90% Approval: 91.95%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	10/25/2013	11/7/2013	Quorum: 76.67% Approval: 58.24%	No Consensus 11/1/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	11/1/2013	11/12/2013	Quorum: 76.23% Approval: 56.48%	Support 11/11/13		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Initial Ballot	11/4/2013	11/13/2013	Quorum: 76.12% Approval: 67.35%	Support 11/5/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-006-4	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 75.58%	Support 11/5/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-009-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 68.40%	Support 11/5/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 58.03%	Support 11/5/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-011-1	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.52% Approval: 71.35%	Support 11/5/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Initial Ballot	11/4/2013	11/15/2013	Quorum: 76.42% Approval: 77.82%	Support 11/5/13		
440	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Final Ballot	11/8/2013	11/18/2013	Quorum: 81.68% Approval: 74.34%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Additional Ballot	11/8/2013	11/20/2013	Quorum: 81.69% Approval: 82.97%	No Consensus 8/26/13		
442	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.05% Approval: 73.46%	Support 8/31/13		
443	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.84% Approval: 69.42%	Support 8/31/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	11/13/2013	11/22/2013	Quorum: 80.54% Approval: 57.59%	Support 8/31/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	11/15/2013	11/25/2013	Quorum: 80.81% Approval: 69.43%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	11/15/2013	11/25/2013	Quorum: 81.06% Approval: 66.09%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	12/2/2013	12/12/2013	Quorum: 75.29% Approval: 64.24%	No Consensus 12/9/13	Affirmative	
448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	12/6/2013	12/16/2013	Quorum: 82.25% Approval: 43.29%	No Consensus 12/15/13	Affirmative	Highlights of comments received expressed: • Agreement with the methodology to determine BES locations for which data had to be captured • Use of the term "locations" • DDR for Flowgates, IROLs • Clarification needed for some data that is to be captured • Editorial suggestions
449	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Final Ballot	12/6/2013	12/16/2013	Quorum: 87.53% Approval: 77.49%	Support 8/31/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-006-4	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 80.77%	Support 11/5/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-009-2	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 72.86%	Support 11/5/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-011-1	Final Ballot	12/10/2013	12/20/2013	Quorum: 84.78% Approval: 72.91%	Support 11/5/13	Affirmative	
453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative	
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative	
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative	

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments	
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative		
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14	
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative		
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative		
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative		
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative		
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative		
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14	
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative		
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative		
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--		
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain		
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative		
473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-4, VAR-002-3	Final Ballot	4/23/2014	5/5/2014	Quorum: 83.84% Approval: 88.26%	Support--4/10/14	Affirmative		
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	5/1/2014	5/5/2014	Quorum: 92.53% Approval: 85.61%	Support--4/23/14	Abstain		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	5/6/2014	5/15/2014	Quorum: 85.79%/79.08% Approval: 86.28%/78.81%	No Consensus--5/15/14	Reject		
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Affirmative Negative Affirmative Affirmative		
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative		
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes			

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483	Project 2014-02	Rich Hydro Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14		
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14		
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative	
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative	
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative	
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative	
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative	
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative	
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and	Additional Ballot	9/3/2014	9/12/2014	Quorum: 84.33% Approval: 76.03%	Support--9/4/14	Affirmative	
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	Quorum: 85.75%/84.96%/84.96%/85.22%/84.96%/85.22%/85.49%/85.22%/86.28%/83.11%/83.91% Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative 9/18/14		
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79% Approval:	Affirmative--10/7/14		

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11
25.	N/A	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CAN-0024 CIP-002 through CIP-009		5/20/11	6/10/11	
26.	N/A	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	CAN-0029 PRC-004-1 R1, R2 and R3		5/20/11	6/10/11	
27.	N/A	CAN-0030--Draft CAN-0030 Attestations	CAN-0030 Attestations		5/20/11	6/10/11	
28.	N/A	CAN-0039--Draft CAN-0039 DOE Form 407	CAN-0039 DOE Form 407		5/20/11	6/10/11	

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
29.	Project 2010-05.1	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)			6/10/11	7/11/11	
30.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		6/15/11	7/15/11	Yes 7/15/11
31.	Project 2010-07	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards		6/17/11	7/17/11	Yes 7/15/11
32.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		6/15/11	8/1/11	Yes 8/1/11
33.	NERC RoP	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Appendices 4B and 4C		6/30/11	8/15/11	
34.	N/A	Compliance Application Notice (CAN) Process	CAN Process		8/15/11	9/6/11	Yes 9/6/11
35..	N/A	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	CAN-0016 CIP-001, R1		8/15/11	9/6/11	Yes 9/6/11
36.	N/A	DRAFT CANs Posted for Comment and Retirement of CAN-0001 through 0004	CAN-0001 through 0004 Retirement		8/31/11	9/21/11	
37.	NERC RSDP	NERC 2012-2014 Reliability Standards Development Plan	2012-2014 RSDP		9/12/11	9/26/11	Yes 9/26/11
38.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		8/15/11	9/28/11	Yes 9/28/11
39.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	BES Definition		8/26/11	10/10/11	Yes 10/10/11

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
40.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Technical Principles for Demonstrating BES Exceptions	Technical Principles for Demonstrating BES Exceptions		8/26/11	10/10/11	Yes 10/10/11
41.	N/A	New CAN Template, five DRAFT CANs for Industry review and CANs Status posted to NERC Compliance's Web site.	CANs		9/23/11	10/14/11	Yes 10/14/11
42.	RoP	Proposed Changes to NERC Rules of Procedure and All Appendices			9/2/11	10/17/11	
43.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	RoP Section 509, Section 1703 and Appendix 5C		9/13/11	10/27/11	Yes 10/27/11
44.	N/A	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	CAN-0010 Definition of Annual		10/10/11	10/31/11	Yes 10/31/11
45.	N/A	CAN-0011--PRC-005-1 R2: New Equipment	CAN-0011 PRC-005-1 R2		10/10/11	10/31/11	Yes 10/31/11
46.	N/A	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	CAN-0012 Completion of Periodic Activity Requirements		10/10/11	10/31/11	Yes 10/31/11
47	N/A	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	CAN-0013 PRC-023 R1 and R2		10/10/11	10/31/11	
48.	N/A	CAN-0015--Unavailability of NERC Software Tools	CAN-0015 NERC Tools		10/10/11	10/31/11	Yes 10/31/11
49.	N/A	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN-0022 VAR-002-1.1b R1 and R3		10/10/11	10/31/11	
50.	N/A	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN-0024 CIP-002, R3		10/10/11	10/31/11	Yes 10/31/11
51.	N/A	CAN-0026--TOP-006 R3 Protection Relays	CAN-0026 TOP-006, R3		10/10/11	10/31/11	Yes 10/31/11
52.	N/A	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN-0028 TOP-006-1, R1.2		10/10/11	10/31/11	

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53.	N/A	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002		10/19/11	11/9/11	
54.	N/A	CAN-0030--Attestations	CAN-0030		10/19/11	11/9/11	
55.	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	MOD-028, R3.1		10/3/11	11/16/11	Yes 11/16/11
56.	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Interpretation of COM-002-2, R2		10/4/11	11/18/11	Yes 11/18/11
57.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		10/5/11	11/18/11	Yes 11/18/11
58.	N/A	Draft Directive Regarding Generator Transmission Leads	Draft Directive #2011 CAG-001		10/17/11	11/18/11	Yes 11/18/11
59.	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy	Interpretation of CIP-006-1, R1.1		10/12/11	11/21/11	Yes 11/21/11
60.	N/A	CAN-0040 - BAL-003 Frequency Bias Calculation			11/2/11	11/23/11	
61.	N/A	CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence	PRC-005 Evidence		11/2/11	11/23/11	Yes 11/22/11
62.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1			12/8/11	Yes 12/8/11
63.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2			12/12/11	Yes 12/12/11
64.	N/A	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	CAN-0027 TOP-003, R2		11/22/11	12/14/11	
65.	NERC RoP	Proposed Changes to the NERC Rules of Procedure and Associated Appendices			11/7/11	12/22/11	

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66.	NERC RoP	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011			11/22/11	12/22/11	
67.	Regional Standard	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		11/22/11	12/22/11	
68.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards)	Version 5 CIP Standards		11/7/11	1/6/12	Yes 1/6/12
69.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2	TOP-001-2 TOP-002-3 TOP-003-2		12/14/11	1/12/12	Yes 1/12/12
70.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition, Phase 2		1/4/12	2/3/12	Yes 2/3/12
71.	N/A	Order 754 - Request for Data or Information	Data Request		12/22/11	2/6/12	Yes 2/6/12
72.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001 COM-002 IRO-001-3		1/9/12	2/9/12	Yes 2/8/12
73.	WECC Regional Standard	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	BAL-004-WECC-02		1/23/12	3/9/12	
74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	
75.	N/A	NERC Functional Model Demand Response Functions and Entities	NERC Functional Model		2/13/12	3/14/12	
76.	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 for WECC	Interpretation of CIP-004-1		2/8/12	3/23/12	Yes 3/23/12

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77.	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Interpretation of CIP-002-1, R3		2/8/12	3/23/12	Yes 3/23/12
78.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR - 002 for Constellation	Interpretation of VAR -002		2/8/12	3/23/12	Yes 3/23/12
79.	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing - PRC-005	PRC-005-2		2/28/12	3/28/12	Yes 3/28/12
80.	Project 2007-09	Project 2007-09 Generator Verification - MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		2/29/12	3/29/12	Yes 3/29/12
81.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - FAC-003-X, FAC-003-3	FAC-003-X FAC-003-3		3/9/12	4/9/12	Yes 4/9/12
82.	Project 2007-09	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		2/29/12	4/16/12	Yes 4/16/12
83.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - PRC-005-1.1a	PRC-005-1.1a		3/2/12	4/16/12	Yes 4/16/12
84.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations	TOP-001 through TOP-008 and PER-001		3/22/12	4/20/12	Yes 4/20/12
85.	Project 2012-INT-02	Request for Interpretation - Project 2012-INT-02 TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		4/24/12	5/4/12	
86.	Project 2008-06	Project 2008-06 - Cyber Security Order 706 Version 5 CIP	CIP-002 and CIP-003 - Comment Form A		4/12/12	5/21/12	Yes 5/20/12
			CIP-004 thru CIP-007 - Comment Form B		4/12/12	5/21/12	Yes 5/20/12
			CIP-008 thru CIP-011 - Comment Form C		4/12/12	5/21/12	Yes 5/20/12

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			Definitions and Implementation Plan - Comment Form D		4/12/12	5/21/12	Yes 5/20/12
87.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		4/25/12	5/24/12	Yes 5/24/12
88.	Project 2007-12	Project 2007-12 Frequency Response Technical Conferences			5/30/12	6/15/12	
89.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003		5/7/12	6/20/12	Yes 6/20/12
90.	N/A	Adequate Level of Reliability Revised Definition and Associated Documents	Adequate Level of Reliability (ALR)		4/25/12	6/25/12	Yes 6/25/12
91.	N/A	Order 754 - Request for Data or Information	Data Request		5/11/12	6/25/12	Yes 6/25/12
92.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR - 002 for Constellation	Interpretation of VAR -002		5/22/12	6/27/12	Yes 6/27/12
93.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		5/29/12	6/27/12	Yes 6/27/12
94.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserve	BAL-001-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-002-2		6/4/12	7/3/12	Yes 7/3/12
			BAL-012-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-013-1		6/4/12	7/3/12	Yes 7/3/12
95.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		5/21/12	7/5/12	Yes 7/5/12
96.	N/A	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	CEAP		5/7/12	7/6/12	Yes 7/6/12
97.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001, COM-002 and IRO-001-3		6/7/12	7/6/12	Yes 7/6/12
98.	Project 2006-02	Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		6/19/12	7/9/12	Yes 7/9/12

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99.	N/A	Standard Processes Manual Revisions to Implement SPIG Recommendations	SPIG Reco		6/20/12	7/19/12	Yes 7/19/12
100.	Project 2012-INT-02	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee	- Interpretation of TPL-003-0a and TPL-004-0		6/20/12	7/20/12	Yes 7/19/12
101.	Project 2012-INT-05	Interpretation of 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		6/27/12	7/27/12	Yes 7/27/12
102.	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision to Address Interpretation of VAR-002 for Constellation	Rapid Revision to VAR-002		7/18/12	7/27/12	Yes 7/26/12
103.	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Rapid Revision of TOP-006		6/14/12	7/30/12	Yes 7/27/12
104.	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Glossary of Terms		6/19/12	8/2/12	Yes 8/2/12
105.	N/A	Reliability Guideline: System Operator Verbal Communications – Current Industry Practices	System Operator Verbal Communications		6/26/12	8/10/12	Yes 8/9/12
106.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		7/27/12	8/27/12	Yes 8/27/12
107.	Project 2010-11	Project 2010-11 - TPL Table 1 Order TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		7/31/12	8/29/12	Yes 8/29/12
108.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs			7/31/12	8/30/12	
109.	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group			7/25/12	9/4/12	
110.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		8/3/12	9/4/12	Yes 9/4/12
111.	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Misoperations)			7/25/12	9/7/12	Yes 9/7/12

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112.	N/A	Definition of Adequate Level of Reliability	Adequate Level of Reliability (ALR)		8/15/12	9/13/12	Yes 9/13/12
113.	N/A	2013-2015 Reliability Standards Development Plan	2013-2015 RSDP		8/17/12	9/18/12	Yes 9/18/12
114.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols	COM-003-1		8/22/12	9/20/12	Yes 9/20/12
115.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		8/29/12	9/27/12	
116.	SPP Regional Standard	Regional Reliability Standard PRC-006-SPP-01 Automatic Underfrequency Load Shedding	PRC-006-SPP-01		8/15/12	9/28/12	
117.	Project 2008-06 Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		9/11/12	10/10/12	Yes 10/10/12
			RSAW		9/11/12	10/10/12	Yes 10/10/12
118.	MRO SPM	Regional Reliability Standards - MRO Standards Process Manual			8/28/12	10/11/12	
119.	N/A	Standard Process Manual Revisions to Implement SPIG Recommendations	SPIG Reco		8/29/12	10/12/12	Yes 10/10/12
120.		Revisions to Outstanding VRFs and VSLs			9/5/12	10/19/12	
121.	Project 2013-01	Project 2013-01 - Cold Weather Preparedness			9/25/12	10/24/12	
122.	Project 2007-09	Project 2007-09 - Generator Verification			9/28/12	10/29/12	
123.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System			10/4/12	11/5/12	
124.	2007-12	Project 2007-12 - Frequency Response			10/5/12	11/7/12	
125.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		10/26/12	11/7/12	
126.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025		10/5/12	11/7/12	

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127.	N/A	IRO-006-WECC-2			10/3/12	11/16/12	
128.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B			10/5/12	11/19/12	
129.	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		10/22/12	12/5/12	Yes 12/5/12
130.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		10/25/12	12/10/12	Yes 12/10/12
131.	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	- Interpretation of CIP-003-3		11/9/12	12/10/12	Yes 12/10/12
132.	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	- Interpretation of CIP-007-3		11/9/12	12/10/12	Yes 12/10/12
133.	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols - RSAW	COM-003-1		11/14/12	12/13/12	Yes 12/13/12
			COM-003-1 RSAW		11/14/12	12/13/12	Yes 12/13/12
134.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		11/16/12	12/17/12	Yes 12/17/12
135.	Project 2012-INT-05	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		11/6/12	12/20/12	Yes 12/20/12
136.	N/A	Standard Processes Manual to Implement SPIG Revisions	SPIG Reco		11/21/12	12/20/12	Yes 12/20/12
137.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		12/10/12	1/11/13	Yes 1/11/13
138.	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	PRC-024-1		12/12/12	1/11/13	Yes 1/11/13
139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13

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143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13
150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13

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155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13
163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13

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169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13
175	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	BAL-002-2	Formal	8/2/13	9/16/13	Yes 9/16/13
176	Project 2009-03	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2.1b EOP-002-3.1 EOP-003-2	5-year review	8/6/13	9/19/13	Yes 9/19/13
177	Project 2012-09	Project 2012-09 IRO Five-Year Review	IRO-003-2 IRO-004-2 IRO-005-4 IRO-006-5 IRO-006-East IRO-008-1 IRO-009-1 IRO-010-1a	5-year review	8/7/13	9/20/13	Yes 9/20/13
178	Project 2008-02	Project 2008-02 Undervoltage Load Shedding	Revised SAR	Informal	9/10/13	10/9/13	Yes 10/9/13
179	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	9/4/13	10/18/13	Yes 10/18/13
180	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition	Formal	9/27/13	10/28/13	Yes 10/28/13

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181	Project 2007-02	Project 2007-02 Operating Personnel Communications Protocols	COM-002-4	Formal	10/21/13	11/7/13	Yes 11/4/13
182	Project 2010-01	Project 2010-01 Training	PER-005-2	Formal	9/27/13	11/12/13	Yes 11/12/13
183	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	Various INT Standards	Formal	9/30/13	11/13/13	Yes 11/13/13
184	Project 2012-05	Project 2012-05 ATC Revisions (MOD A)	MOD-001-2	Formal	10/4/13	11/20/13	Yes 11/18/13
185	Project 2010-03	Project 2010-03 Modeling Data (MOD B)	MOD-032-1, MOD-033-1	Formal	10/07/13	11/20/13	
186	Project 2010-04	Project 2010-04 Demand Data (MOD C)	MOD-031-1	Formal	10/09/13	11/22/13	Yes 11/22/13
187	Project 2013-04	Project 2013-04 Voltage and Reactive Control	VAR-001-4, VAR-002-3	Formal	10/11/13	11/25/13	Yes 11/25/13
188	Project 2009-03	Project 2009-03 Emergency Operations	SAR	Informal	11/06/13	12/05/13	Yes 12/5/13
189	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-002-2	Formal	10/28/13	12/11/13	Yes 12/11/13
190	Project 2007-11	Project 2007-11 - Disturbance Monitoring	PRC-002-2	Formal	11/01/13	12/16/13	Yes 12/16/13
191	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-027	Formal	11/04/13	12/18/13	Yes 12/18/13
192	Project 2014-01	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	SAR	Formal	11/20/13	12/19/13	Yes 12/19/13
193	Project 2010-01	Project 2010-01 Training - PER-005-2	PER-005-2	Formal	12/4/13	1/22/14	Yes 1/17/14
194	Project 2010-03	Project 2010-03 Modeling Date - MOD B	MOD-033-1	Formal	12/6/13	1/22/14	Yes 1/21/14
195	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	INT-004-3 INT-010-2	Formal	1/10/14	1/24/14	Yes 1/22/14
196	Project 2007-02	Project 2007-02 Operating Personnel	COM-002-4	Formal	1/22/14	1/31/14	Yes 1/31/14
197	Project 2014-02	Project 2014-02 Standard Authorization Request – Cyber Security Standards	CIP SAR	Informal	1/17/14	2/18/14	Yes 2/18/14
198	2014 Work Plan	2014 Work Plan for NERC Reliability Standards Development	2014 Work plan			2/21/13	Yes 2/21/14

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199	Project 2010-17	Project 2010-17 Definition of Bulk Electric System - Phase 2	BES	Informal	1/29/14	2/27/14	Yes 2/27/14
200	Project 2010-05.1	Project 2010-05.1 Protection System: Phase 1 (Misoperations) - PRC-004-3	PRC-004-3	Formal	1/17/14	3/11/14	Yes 3/2/14
201	Project 2012-13	Project 2012-13 NUC-Nuclear Plant Interface Coordination Standard Authorization Request	NUC-001-2.1 SAR	Informal	2/12/14	3/13/14	Yes 3/13/14
202	Project 2010-05.2	Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) - SAR	SAR	Informal	2/18/14	3/19/14	Yes 3/19/14
203	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	SAR	Formal	02/21/14	03/24/14	Yes 3/24/14
204	Project 2014-03	Technical Conferences on Revisions to TOP/IRO Reliability Standards	Technical Conference Topics	Informal	03/11/14	03/24/14	
205	Project 2014-04	Project 2014-04 - Physical Security	SAR	Informal	03/21/14	03/28/14	Yes 3/28/14
206	Project 2010-14.2	Project 2010-14.2 - Periodic Review of BAL Standards	Reco to Revise BAL-005 and BAL-006	Formal	02/21/14	04/07/14	
207	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Informal	03/11/14	04/09/14	Yes 4/9/14
208	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	02/25/14	04/10/14	Yes 4/10/14
209	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-002-3	Formal	02/27/14	04/14/14	Yes 4/14/14
210	Project 2008-02	Project 2008-02 - Undervoltage Load Shedding - PRC-010, PRC-020, PRC-021 and PRC-022	PRC-010-1	Informal	03/17/14	04/16/14	Yes 4/16/14
211	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	CIP-014-1	Formal	04/10/14	04/24/14	Yes 4/24/14
212	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Informal	03/28/14	04/28/14	Yes 4/28/14

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213	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	04/17/14	05/05/14	Yes 5/5/14
214	Project 2010-02	Project 2010-02 – Connecting New Facilities to the Grid	FAC-001-1 FAC-002-1	Formal	04/01/14	05/15/14	Yes 5/15/14
215	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Informal	04/22/14	05/21/14	Yes 5/21/14
216	Project 2012-13	Project 2012-13 Nuclear Plant Interface Coordination	NUC-001-3	Formal	04/08/14	05/22/14	Yes 5/22/14
217	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)	PRC-005-X	Formal	04/17/14	06/03/14	Yes 6/3/14
218	Project 2010-13.3	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	Formal	04/25/14	06/09/14	Yes 6/9/14
219	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	05/09/14	06/25/14	Yes 6/25/14
221	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Informal	05/23/14	06/23/14	Yes 6/23/14
222	Project 2010-05-1	Project 2010-05-1 Protection System – Phase 1 – Misoperations	PRC-004	Formal	05/16/14	07/09/14	Yes 7/9/14
223	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	05/19/14	07/02/14	Yes 7/2/14
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14
225	Project 2015-2017	Project 2015-2017 Reliability Standard		Informal		7/21/14	Yes 7/21/14

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		Development Plan					
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and BAL-006	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14
231	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Formal	07/2/14	08/15/14	Yes 8/13/14
232	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-004-2.1a(X) PRC-004-3(X)	Formal	07/10/14	08/26/14	Yes 8/25/14
233	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays) – PRC-005-X	PRC-005-X	Formal	07/30/14	09/12/14	Yes 9/12/14
234	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	08/6/14	09/19/14	Yes 9/22/14
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14

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236	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	09/26/14	10/06/14	Yes 10/6/14
237	Project 2008-02	Project 2008-02: Underfrequency Load Shedding (UFLS)	PRC-006-2	Formal	08/21/14	10/08/14	Yes 10/7/14
238	Project 2013-03	Project 2013-03: Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	08/27/14	10/10/14	Yes 10/10/14
239	NERC Rules of Procedure	NERC Rules of Procedure	NERC Rules of Procedure	Formal	08/26/14	10/10/14	Yes 10/14/14
240	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems Phase 2 of Protection Systems	RAS Definition	Formal	08/29/14	10/14/14	Yes 10/14/14
241	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	VAR-002-2b(X) VAR-002-4	Formal	08/27/14	10/16/14	Yes 10/16/14
242	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-003-6 CIP-010-2 CIP-003-X CIP-004-X CIP-007-X CIP-010-X CIP-011-X	Formal	09/03/14	10/17/14	Yes 10/17/14
243	Project 2009-03	Project 2009-03 Emergency Operations	EOP-011-1	Formal	09/05/14	10/20/14	Yes 10/20/14
244	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Preliminary Draft 5)	PRC-027-1	Informal	10/01/14	10/21/14	Yes 10/21/14
245	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	09/05/14	10/21/14	Yes 10/21/14
246	Project 2014-01	Project 2014-01 Applicability for Dispersed Generation	PRC-004-2.1a(X) PRC-004-4	Formal	09/05/14	10/22/14	Yes 10/22/14
247	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	10/10/14	11/10/14	Yes 11/10/14
248	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1	TPL-007-1	Formal	10/28/14	11/21/14	Yes 11/24/14
249	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	11/04/14	11/24/14	Yes 11/25/14
250	Project 2014-01	Project 2014-01 – Standards Applicability	PRC-001-1.1 PRC-019-2	Formal	11/05/14	12/23/14	Yes 12/22/14

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		for Dispersed Generation Resources	PRC-024-1				
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15
255	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-5	Informal	12/22/14	1/20/15	Yes 1/22/15
257	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	1/29/15	3/18/15	Yes 3/16/15
258	Reliability Guideline	Reliability Guideline: Loss of Real-Time Reliability Tools Capability/Loss of Equipment Significantly Affecting ICCP Data		Formal	2/19/15	4/6/15	Yes 4/6/15
259	Project 2008-02.2	Project 2008-02.2 Phase 2 UVLS: Misoperation	PRC-010-2	Formal	2/20/15	4/7/15	Yes 4/7/15
260	Project 2014-04	Project 2014-04 Physical Security	CIP-014-2	Formal	2/20/15	4/9/15	Yes 4/9/15
261	Project 2015-04	Project 2015-04 Alignment of Terms	SAR	Formal	2/24/15	4/13/15	Yes 4/13/15
262	Project 2007-17.4	Project 2007-17.4 PRC-005 Order No. 803 Directives	SAR	Informal	3/12/15	4/10/15	Yes 4/13/15
263	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	SAR	Informal	3/16/15	4//15/15	Yes 4/15/15
264	Project 2010-14.2.2	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	SAR	Informal	3/17/15	4//15/15	Yes 4/15/15

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265	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-008-1	Informal	3/27/15	5/11/15	Yes 5/11/15
266	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-006-2	Informal	3/27/15	5/11/15	Yes 5/11/15
267	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-005-2	Informal	3/27/15	5/11/15	Yes 5/11/15
268	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-004-2	Informal	3/27/15	5/11/15	Yes 5/11/15
269	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Draft 5)	PRC-027-1	Formal	4/1/15	5/15/15	Yes 5/15/15
270	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	SAR	Informal	4/16/15	5/19/15	Yes 5/19/15
271	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems – RAS	PRC-012-2	Informal	4/30/15	5/20/15	Yes 5/20/15
272	Project 2015-03	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3 FAC-011-3 FAC-014-2	Formal	5/4/15	6/17/15	Yes 6/17/15
273	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	IRO-006-East-2 IRO-009-2	Formal	5/21/15	7/8/15	Yes 7/8/15
274	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	PRC-005-3	Formal	6/11/15	7/10/15	Yes 7/10/15
275	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generations Resources	PRC-004-2.1 PRC-005-2 PRC-005-3	Informal	6/12/15	7/13/15	Yes 7/13/15
276	Project 2015-07	Project 2015-07 Internal Communications Capabilities	COM-001-2	Informal	6/11/15	7/15/15	Yes 7/15/15
277	Project 2015-04	Alignment of Terms	Glossary Terms	Formal	6/12/15	7/23/15	Yes 7/23/15
278	Project 2009-02	Real-time Monitoring and Analysis Capabilities	SAR	Formal	7/16/15	8/17/15	Yes 8/17/15
279	NERC 2016-2018	Reliability Standards Development Plan	Development Plan	Formal	7/16/15	8/17/15	Yes 8/17/15
280	Project 2015-08	Emergency Operations	EOP-004-2 EOP-005-2 EOP-006-2 EOP-008-1	Informal	7/21/15	8/19/15	Yes 8/19/15
281	Project 2010-14.1	Phase 1 of Balancing Authority Reliability-	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15

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		based Controls					
282	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15
283	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	7/29/15	9/11/15	Yes 9/11/15
284	Project 2007-06	System Protection Coordination	PRC-027-1	Formal	7/29/15	9/11/15	Yes 9/11/15
285	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 BAL-006-3	Formal	7/30/15	9/14/15	Yes 9/14/15
286	Project 2007-17.4	PRC-005 FERC Order No. 803 Directive	PRC-005-6	Formal	7/30/15	9/16/15	Yes 9/16/15
287	Project 2010-04.1	MOD-031 FERC Order No. 804 Directives	MOD-031-2	Formal	7/31/15	9/18/15	Yes 9/18/15
288	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010-3 FAC-011-3 FAC-014-2	Informal	8/20/15	9/21/15	Yes 9/21/15
289	Project 2010-07.1	Vegetation Management	FAC-003-3	Informal	8/24/15	9/28/15	Yes 9/28/15
290	Project 2010-05.3	Phase 3 of Protection Systems: Remedial Action Schemes	PRC-012-2	Formal	8/20/15	10/5/15	Yes 10/5/15
291	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	9/24/15	11/9/15	Yes 11/9/15
292	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls	BAL-004-0	Formal	9/24/15	11/12/15	Yes 11/12/15
293	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	9/25/15	11/16/15	Yes 11/16/15
294	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	10/6/15	11/19/15	Yes 11/19/15
295	Project 2010-07.1	Vegetation Management	FAC-003-3	Formal	10/30/15	12/16/15	Yes 12/16/15
296	Project 2015-10	Single Points of Failure SAR	TPL-001	Informal	11/12/15	12/17/15	Yes 12/17/15
297	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	11/25/15	1/8/16	Yes 1/8/16
298	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 FAC-001-3 BAL-006-2	Formal	12/31/15	1/11/16	Yes 1/11/16
299	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	12/10/15	1/25/16	Yes 1/25/16
300	Project 2016-01	Modifications to TOP and IRO Standards	SAR	Informal	1/22/16	2/22/16	Yes 2/22/16
301	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	2/3/16	3/18/16	Yes 3/18/16
302	Project	Modifications to CIP	SAR	Informal	3/23/16	4/21/16	Yes

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					4/21/16
303	Project 2007-06.2	Phase 2 of System Protection Coordination	PER-006-1 & Two Definitions	Formal	3/10/16	4/25/16	Yes 4/25/16
304	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	3/23/16	5/9/16	Yes 5/6/16
305	CEP	Cost Effectiveness Pilot	TPL-001-4	Informal	4/27/16	5/26/16	Yes 5/26/16
306	Project 2013-03	Geomagnetic Disturbance Mitigation Revised White Papers	SAR	Informal	5/12/16	6/13/16	Yes 6/13/16
307	Project 2015-10	Single Points of Failure	SAR	Informal	5/26/16	6/24/16	Yes 6/24/16
308	Project 2016-02	Modifications to CIP Standards	SAR	Informal	6/1/16	6/30/16	Yes 6/30/16
309	Draft 2017-2019	Reliability Standards Development Plan	RSDP	Informal	6/20/16	7/19/16	Yes 7/19/16
310	EPR	Enhanced Periodic Review Standing Review Team	Standards Grading	Informal	6/30/16	8/1/16	Yes 8/1/16
311	Project 2016-01	Modifications to TOP and IRO Standards	IRO-002-5 TOP-001-4	Formal	6/20/16	8/3/16	Yes 8/3/16
312	Project 2015-09	Establish and Communicate System Operating Limits	FAC-014-3	Formal	7/14/16	8/12/16	Yes 8/12/16
313	Project 2015-09	Establish and Communicate System Operating Limits	FAC-011-4	Formal	7/14/16	8/12/16	Yes 8/12/16
314	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3 EOP-008-2	Formal	6/30/16	8/15/16	Yes 8/15/16
315	Project 2016-02	Modifications to CIP Standards	CIP-003-7	Formal	7/21/16	9/6/16	Yes 9/6/16
316	FMAG	Functional Model Advisory Group	Reliability Functional Model and Technical Document	Informal	7/21/16	9/7/16	Yes 9/7/16
317	Project 2015-08	Emergency Operations	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16
318	Project 2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	CIP-002-5.1	Formal	7/27/16	9/12/16	Yes 9/12/16

RSC Meeting #16-5, Agenda Item 6.3: Comment History

(As of 9/23/2016)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE. OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

August 29th, 2016:

Effective August 16th, 2016 a letter order approving the NERC and Northeast Power Coordinating Council, Inc. (NPCC) joint petition to retire NPCC Regional Reliability Standard PRC -002-NPCC-01 was issued by FERC. The Letter Order is issued in Docket No. RD16-8-000.

Please use the following link to access the FERC Letter Order Issued in Docket No. RD16-8-000: Docket No. RD16-8-000: Approval of Retirement of Regional Reliability Standard PRC-002-NPCC-01

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD16-8-000

August 16, 2016

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Lauren A. Perotti
Counsel for North American Electric Reliability Corporation

Reference: Joint Petition of the North American Electric Reliability Corporation and Northeast Power Coordinating Council for Approval of Retirement of Regional Reliability Standard PRC-002-NPCC-01

Dear Ms. Perotti:

On June 9, 2016, the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordination Council, Inc. (NPCC) filed a joint petition for Commission approval, pursuant to section 215(d)(1) of the Federal Power Act (FPA)[1] and Section 39.5[2] of the Commission's regulations, of the retirement of NPCC Regional Reliability Standard PRC-002-NPCC-01 (Disturbance Monitoring) and the two related NPCC regional definitions, Current Zero Time and Generating Plant.[3]

In the joint petition, NERC and NPCC state that the primary purpose of Regional Reliability Standard PRC-002-NPCC-01 is to ensure that adequate disturbance data is available to facilitate bulk electric system event analyses. NERC and NPCC explain that the issues addressed in the Regional Reliability Standard are now addressed by continent-wide Reliability Standard PRC-002-2 (Disturbance Monitoring and Reporting

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2015).

3 In 2011, the Commission approved Regional Reliability Standard PRC-002-NPCC-01 and the two related NPCC regional definitions. *See North. American. Electric. Reliability Corp.*, 137 FERC ¶ 61,043 (2011).

Requirements), approved by the Commission in 2015.[4] Reliability Standard PRC-002-2 imposes mandatory requirements concerning the monitoring and reporting of disturbances and provides greater continent-wide consistency regarding collection methods for data used in the analysis of disturbances on the Bulk-Power System. According to NERC and NPCC, Regional Reliability Standard PRC-002-NPCC-01 and the related definitions are now redundant and unnecessary for reliability and should be retired.

The NERC and NPCC joint petition was noticed on June 9, 2016, with interventions, comments and protests due on or before July 11, 2016. Dominion Resources Service, Inc. filed a timely motion to Intervene. No comments or protests were received.

The NERC and NPCC uncontested joint petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2015), effective as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2015).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

[4] Order No. 814, *Disturbance Monitoring and Reporting Requirements Reliability Standard*, 152 FERC ¶ 61,198 (2015).

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE. OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

PRC-006-NPCC-02 Automatic Underfrequency Load Shedding

AGENDA FOR MEETING #1
June 3, 2016 9:00 a.m. – 4:00 p.m. EST
NPCC Office
1040 Avenue of Americas 10th Floor
New York, NY
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada) **Guest Code: 641425432**
Password: 21818644

Attendees:

	Name	Organization	Comment
1.	Guy Zito	Northeast Power Coordinating Council	In Person
2.	Gerry Dunbar	Northeast Power Coordinating Council	In Person
3.	Ruida Shu	Northeast Power Coordinating Council	In Person
4.	Vincent Morissette	Hydro Québec TransÉnergie	In Person
5.	Dean Latulipe	National Grid	In Person
6.	Dan Taft	Con Edison	In Person
7.	Tim Kucey	PSEG Fossil	In Person
8.	Brian Robinson	Utility Services	Via Phone
9.	Nick Parrott	NY Municipal Utilities	Via Phone
10.	Jeannette Gauthier	Hydro Québec TransÉnergie	Via Phone
11.	Hamid Hamadanizadeh	Hydro One	Via Phone
12.	David Gordon	MMWEC	Via Phone

Introductions and Chair's Remarks
Guy Zito provided a brief summary of the NPCC office location.
Self-introductions were performed around the room.
Guy Zito indicated the importance of following the steps of NPCC Regional Standard Processes Manual.

Dan Taft called the meeting in order at 9:00AM.

NPCC Antitrust Compliance Guidelines
The NPCC Antitrust Compliance Guidelines were read by Ruida Shu.

Agenda Items:

1. **Purpose of this Standard Drafting Team (SAR)**
   Brian Robison provided a brief summary on the SAR.

The SAR is drafted due to the approval of continent wide standard PRC-006-2 and to avoid double jeopardy with PRC-006-NPCC-1.

Gerry Dunbar indicated that some of the requirements of Directory 12 are more stringent than the regional standard however there are additional requirements in PRC-006-NPCC-01 which are valuable.

Tim Kucey provided some inputs on the requirement 16.3 compensatory load shedding. PRC-024-2 is the standard with generator specific settings on compensatory load shedding.

PRC-006-NPCC-1 falls under NERC since it is approved by FERC.
Ontario and New Brunswick regions accepted PRC-006-NPCC-1.
The standard drafting team can make recommendations to revise or retire Directory 12 to TFSS.

Dan Taft provided an overview on the tasks and goals for the standard drafting team.
The goal is to reduce the UFLS related documents from three to two. (PRC-006-2, PRC-006-NPCC-1 and Directory 12)
There are two ways to approach this:

- Revise the existing PRC-006-NPCC-1 and make recommendations to TFSS to retire Directory 12.
- Retire the existing PRC-006-NPCC-1 and make recommendations to TFSS to revise Directory 12.

If the drafting team were to retire existing PRC-006-NPCC-1 and make recommendations to TFSS to revise Directory 12 it will be more difficult since the revisions will be done by another drafting team.

Action Item:

- Find out from (TFSS) if there are any generators left in the NPCC foot print that trips over the curve.
- Reach out to the continent wide standard drafting team members for PRC-006-2, find out how they handled the compensatory load shedding.

2. **PRC-006-2**

3. **PRC-006-NPCC-1**

The standard drafting team reviewed all the requirements one by one.

Requirement 1:
Did not reach a conclusion with this requirement.
Two options are available:

- Keep the requirement, the requirement will need to be revised with additional clarification.

- Remove the requirement.

Requirement 2:
Action Item:

- Dan Taft proposed to remove requirement 2 from PRC-006-NPCC-1

Requirement 3:
David Gordon provided details on why this requirement exist. It is because the different violation levels for different entities.
Action Item:

- Consider linking this requirement with requirement 1.

Requirement 4:
Action Item:

- Proposed to consider modifying the language for clarification.

Requirement 5:
Action Item:

- Clarification of peak load is necessary.
- Need to add in the provisions for groups.
- It is preferable to keep both TO and DP within the requirement.
- Need to add the applicability of Transmission Owner to the Quebec Interconnection.

Requirement 6:
Action Item:

- Vincent Morissette will go back and research on the specific conditions which suitable for Hydro Quebec footprint.

Requirement 7:
Action Item:

- Vincent Morissette proposed to change or review requirement 7.2 to 100ms for Quebec Interconnection.

Requirement 8:
Action Item:

- Vincent Morissette will provide information related to the historic basis on requirement 8.
- Gerry Dunbar will check with Quoc Le in regards to if this requirement came out of TFSP recommendation.

Requirement 9:
See action item for requirement 8.

Requirement 10:
See action item for requirement 8.

Requirement 11:
See action item for requirement 8.

Requirement 12:
Action Item:

- Consider to modify the language to accommodate the smaller utilities. The goal is to add “rolling average of the peak load for three-five years” for smaller entities on the boarder of 50MW or 100MW.
- To quantify the coincident load is pertaining to the peak.

Requirement 13:

- Keeping the existing requirement 13 the same.

Requirement 14:
Action Item:

- Consider to modify or remove requirement 14.

Requirement 15:
Action Item:

- The drafting team members (Tim Kucey and Dan Taft) will do additional research prior to the next meeting in order to proceed forward.

Requirement 16:
See action item for requirement 3.

Requirement 17:
See action item for requirement 3.

Requirement 18:
See action item for requirement 3.

Requirement 19:

- Keeping the existing requirement 19 the same.

Requirement 20:
Action Item:

- Further discussion is necessary between the regional and continent wide standards.
- Consider mention the over frequency per the continent wide standard for requirement 20.3

Requirement 21:
Action Item:

- Consider revise language to refer to load shedding distribution and if it is applied to Hydro Quebec.

Requirement 22:
See action item for requirement 21.

Requirement 23:
See action item for requirement 21.

4. **Directory 12**

5. **Comparison**

6. **Discussion on the process for approbation**

7. **Next Steps**

The meeting is adjourned on 4:01PM June 3, 2016**.**

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment.

Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

- Industry-related topics considered sensitive or market intelligence in nature that are outside of their committee's scope or assignment, or the published agenda for the meeting;
- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Ruta Skučas, Esq. at 1-202-470-6428.

Information in a Regional Standard Authorization Request (RSAR)

The tables below identify information to be submitted in a Regional Standard Authorization Request to the NPCC Regional Standards Process Manager, NPCCstandard@npcc.org . The NPCC Regional Standards Process Manager shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process.

Regional Standard Authorization Request Form

Title of Proposed Standard:	PRC-006-NPCC-2
Request Date:	03-31-2015

RSAR Requester Information

Name: Brian Robinson		**RSAR Type (Check box for one of these selections.)**	
Company:	NPCC	☐	New Standard
Telephone: 802-241-1400		☒	Revision to Existing Standard
Fax:	(866) 214-8632	☐	Withdrawal of Existing Standard
Email:	Brian.Robinson@utilitysvcs.com	☐	Urgent Action

Purpose (Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.**)**

The purpose of the proposed RSAR is to review regional reliability standard PRC-006-NPCC-1 for potential revisions or retirements made necessary by NERC's PRC-006-1/PRC-006-2 Automatic Underfrequency Load Shedding and PRC-024-1/PRC-024-2 Generator Frequency and Voltage Protective Relay Settings standards.

PRC-006-NPCC-1 is to be reviewed to determine if the applicability of the standard needs to be revised in accordance with Project 2014-01 Dispersed Generation Resources.

PRC-006-NPCC-1 is to be reviewed in order to determine if the performance requirements as contained in the criteria of NPCC Directory#12 Sections 5.1.1 and 5.1.2 should be explicitly included in the requirements of the Regional Standard.

Attachment C in PRC-006-NPCC-1 is to be reviewed to address the implications of the design assessment, in accordance with Requirement R4 of PRC-006-1/PRC-006-2, of not meeting the program performance characteristics as identified in Requirement R3 of PRC-006-1/PRC-006-2.

PRC-006-NPCC-1 is to be reviewed in order to update Table 4 in Attachment C in accordance with the 2013 NPCC UFLS Adequacy Assessment. Additionally, the applicability of Requirements R4 and R5 will be reviewed to consider that Hydro Quebec is not part of the Eastern Interconnection.

Retiring PRC-006-NPCC-1 is to be considered if it is determined that it can be retired without sacrificing the ability to develop an effective underfrequency load shedding program.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation**.)**

To enhance efficiencies and cost effectiveness, it must be determined if PRC-006-NPCC-1 requirements can be revised or retired to address the new NERC BES definition, Paragraph 81, and eliminate redundancy leading to double jeopardy with PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 requirements without sacrificing the ability to develop an effective underfrequency load shedding program.

Brief Description: (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.**)**

The requirements in PRC-006-NPCC-1 will be reviewed individually for revision or deletion with respect to the new NERC BES definition, and Paragraph 81. In addition, PRC-006-NPCC-1 will be reviewed against NERC's PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 2-2. PRC-006-1/PRC-006-2 mandates the establishment of design and documentation requirements for automatic underfrequency load shedding (UFLS) programs. PRC-024-1/PRC-024-2 mandate that Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions. These "umbrellas" encompasses the relevant requirements in PRC-006-NPCC-1. However, the relevant requirements in each of the standards are to be compared and the requirements of PRC-006-NPCC-1, if so determined, are revised or deleted to eliminate redundancy and the

concomitant double jeopardy. The review will also ensure that NERC Rules of Procedure, Section 312. Regional Reliability Standards, bullet 1that reads "Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard." will govern.

PRC-006-1/PRC-006-2 specifies in Requirement R4 that "Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years…" Revision to Attachment C of PRC-006-NPCC-1 needs to be considered to address the circumstance surrounding a design assessment that does not meet the performance characteristics as identified in Requirement R3 of PRC-006-1/PRC-006-2.

Revise Table 4 Attachment C to reflect the modified Quebec UFLS program parameters as recommended in the 2013 NPCC UFLS Adequacy Assessment and review the applicability of Requirements R4 and R5 as they pertain to the Quebec Interconnection.

Additionally, as identified by SS38 there are aspects of the performance requirements in NERC PRC-006-1 that are slightly more relaxed than the criteria in Directory#12 and these more stringent attributes of the NPCC criteria were not incorporated into the regional standard.

Specifically, the NPCC criteria in Directory#12 (Sections 5.1.1 and 5.1.2) state that (1) frequency decline is arrested at no less than 58.0 Hz for the portions of NPCC in the Eastern Interconnection, and 56.0 Hz for the portion of NPCC in the Quebec Interconnection (2) frequency should not remain below 59.5Hz for more than 30 seconds and should not remain below 58.5 Hz. for more than 10 seconds. Review the need to include the performance criteria presently in Directory#12 into PRC-006-NPCC-02, or whether the performance criteria included in PRC-006-1/PRC-006-2 is sufficient.

Interpretations of PRC-006-NPCC-1 to be considered to clarify PRC-006-NPCC-2.

The review will include an assessment of the need to include language to address dispersed generation resources.

PRC-006-NPCC-2 should be made to conform to the NERC Results Based Standard format.

After this review is completed, it will be determined if PRC-006-NPCC-1 should be revised, or retired.

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)

☐	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
☐	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☒	Planning Coordinator	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☒	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☒	Generator Owner	Entity that owns and maintains generating units.
☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
☒	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.

☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☒	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
Recognizing that reliability is an Common Attribute of a robust North American economy:	
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes	
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

Review and compare regional standard PRC-006-NPCC-1with continent-wide standards PRC-006-1/PRC-006-2 and PRC-024-1/PRC-024-2 to determine if revisions are necessary, or retirement of PRC-006-NPCC-01 possible.

Determine the necessity for including wording to address dispersed generation resources.

Consider incorporating more stringent aspects of Directory#12 in order to facilitate future retirement of Directory#12.

Related Standards

Standard No.	Explanation
PRC-006-1/PRC-006-2	NERC Automatic Underfrequency Load shedding
PRC-024-1/PRC-024-2	NERC Generator Frequency and Voltage Protective Relay Settings

Related SARs or RSARs

SAR ID	Explanation

DRAFTING TEAM--RSAR PRC-006-NPCC-02

	Self-Nominations	
1	Dan Taft	Consolidated Edison Company of New York
2	Jonathan Appelbaum	The United Illuminating Company
3	Tim Kucey	PSEG Fossil LLC
4	Vincent Morissette	Hydro-Québec TransÉnergie
5	Dean Latulipe	National Grid
6	Brian Robinson--**RSAR Requester**	Utility Services, Inc.
7	Hamid Hamadani	Hydro One Networks, Inc.
8	Daniel Kidney	NPCC Compliance Staff
9	Ruida Shu	NPCC Standards Staff

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-2

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

      4.2.1 Transmission Owners

      4.2.2 Distribution Providers

   4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **Effective Date:**

   This standard is effective on the first day of the first calendar quarter six months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   PRC-006-2 was developed under Project 2008-02: Underfrequency Load Shedding (UFLS). The drafting team revised PRC-006-1 for the purpose of addressing the directive issued in FERC Order No. 763. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 FERC ¶ 61,098 (2012).

B. Requirements and Measures

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

- Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
- Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
- Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA

(gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per

Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for implementation , including any Corrective Action Plan, per Requirement R9.

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, per Requirement R10.

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall

conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same

islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

R15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. *[VRF: High][Time Horizon: Long-term Planning]*

15.1. For UFLS design assessments performed under Requirement R4 or R5, the Corrective Action Plan shall be developed within the five-year time frame identified in Requirement R4.

15.2. For UFLS design assessments performed under Requirement R12, the Corrective Action Plan shall be developed within the two-year time frame identified in Requirement R12.

M15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall have a dated Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, that was developed within the time frame identified in Part 15.1 or 15.2.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, R14, and R15, Measures M1, M2, M3, M4, M5, M12, M14, and M15 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to	The Planning Coordinator identified an island(s) to serve	The Planning Coordinator identified an island(s) to serve

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				including notification of and a schedule for implementation by UFLS entities within its area
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation,

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	program design and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program,

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.
R15	N/A	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period of up to 1 month.	R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 1 month but not more than 2 months.	R3, but failed to develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. OR The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 2 months.

D. Regional Variances

D.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

D.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

D.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

DA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

DA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

DA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

M.D.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.A.3 Parts D.A.3.1 through DA3.3.

D.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

D.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1A, and

D.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 - Attachment 1A, and

D.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement D.A.4 Parts D.A.4.1 through D.A.4.3.

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
DA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts D.A.3.1, D.A.3.2, and D.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
DA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 but simulation failed to include one (1) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D3 but simulation failed to include two (2) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D3 but simulation failed to include all of the items as specified in Parts D.A.4.1, D.A.4.2 and D.A.4.3. OR

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3

D.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

D.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M.D.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement D.B.1.

D.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per D.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

D.B.2.1. Those islands selected by applying the criteria in Requirement D.B.1, and

D.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

M.D.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per D.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement D.B.2 Parts D.B.2.1 and D.B.2.2.

D.B.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

D.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

D.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

D.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

D.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M.D.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.B.3 Parts D.B.3.1 through D.B.3.3.

D.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

D.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

D.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

D.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation

above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

D.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

D.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

D.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

D.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement D.B.4 Parts D.B.4.1 through D.B.4.7.

D.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

D.B.11.1. The performance of the UFLS equipment,

D.B.11.2 The effectiveness of the UFLS program

M.D.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement D.B.11.

D.B.12. Each Planning Coordinator, in whose islanding event assessment (per D.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.D.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements D.B.12 and D.B.4 if UFLS program deficiencies are identified in D.B.11.

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.2	N/A	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.
D.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, and D.B.3.3 in

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		simulations of underfrequency conditions		simulations of underfrequency conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
D.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include one (1) of the items as specified in Requirement	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include two (2) of the items as specified in	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include three (3) of the items as specified in	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include four (4) or more of the items as

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	D.B.4, Parts D.B.4.1 through D.B.4.7.	Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7. OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2
D.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement D.B.11, Parts D.B.11.1 or D.B.11.2.	evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2.
D.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, failed to participate in

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

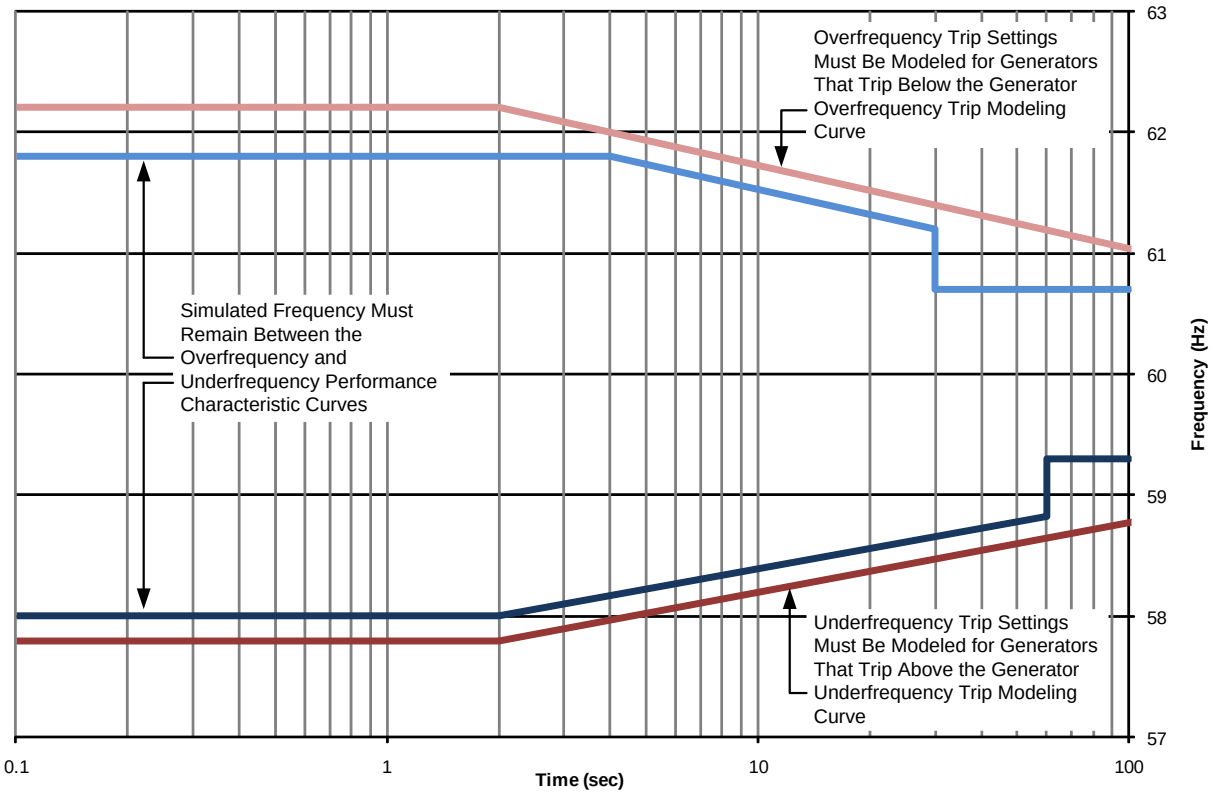
E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 25, 2010	Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.	
1	November 4, 2010	Adopted by the Board of Trustees	
1	May 7, 2012	FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)	
1	November 9, 2012	FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8.	
2	November 13, 2014	Adopted by the Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Revisions to existing Requirement R9 and R10 and addition of new Requirement R15.

PRC-006-2 – Attachment 1

Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



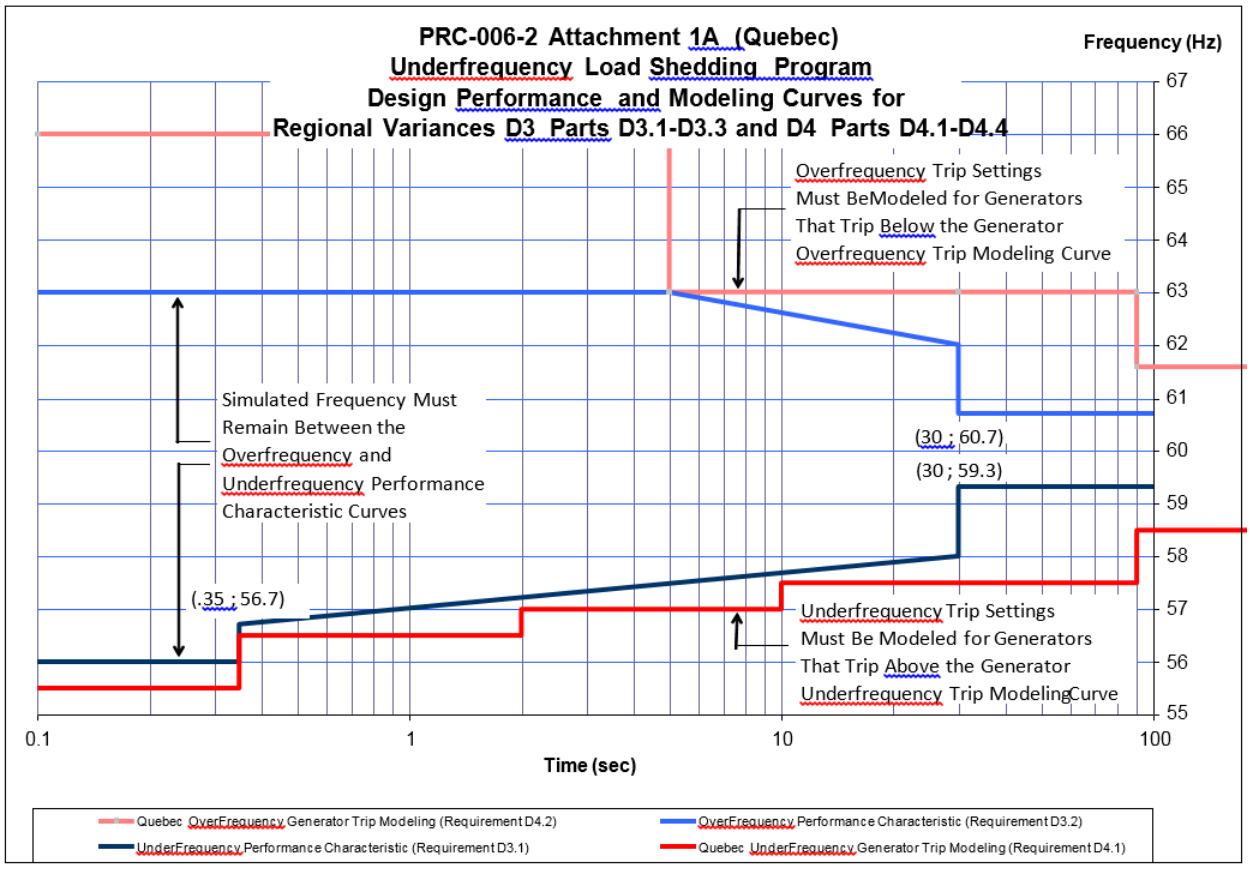
- Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)
- Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
- Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
- Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3)

Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling	Underfrequency Performance Characteristic

t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-2 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances D3 Parts D3.1-D3.3 and D4 Parts D4.1-D4.4
Frequency (Hz)
67
66
65
64
63
62
61
60
59
58
57
56
55
Overfrequency Trip Settings
Must BeModeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip ModelingCurve
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement D4.2)
OverFrequency Performance Characteristic (Requirement D3.2)
UnderFrequency Performance Characteristic (Requirement D3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement D4.1)

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R9:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a Planning Coordinator (PC) assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R10:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R15:

Requirement R15 was added in response to the directive from FERC Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. Requirement R15 addresses the FERC directive by making explicit that if deficiencies are identified as a result of an assessment, the PC shall develop a Corrective Action Plan and schedule for implementation by the UFLS entities.

A "Corrective Action Plan" is defined in the NERC Glossary of Terms as, "a list of actions and an associated timetable for implementation to remedy a specific problem." Thus, the Corrective Action Plan developed by the PC will identify the specific timeframe for an entity to implement corrections to remedy any deficiencies identified by the PC as a result of an assessment.

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-NPCC-1

3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Planning Coordinator

   4.3. Distribution Provider

   4.4. Transmission Owner

5. **Effective Date:** For the Eastern Interconnection & Québec Interconnection portions of NPCC excluding the Independent Electricity System Operator (IESO) Planning Coordinator area of NPCC in Ontario, Canada:

   The effective date for Requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016 The effective date for Requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

   For the Independent Electricity System Operator (IESO) Planning Coordinator's area of NPCC in Ontario, Canada:

   All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

B. Requirements

R1 Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R2 Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3 Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]

R4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R5 Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations

from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

R6 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R7 Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

7.1 Eastern Interconnection – 100 ms

7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R8 Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R9 Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R10 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R11 Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R12 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

R13 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R14 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R15 Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net

capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is

required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

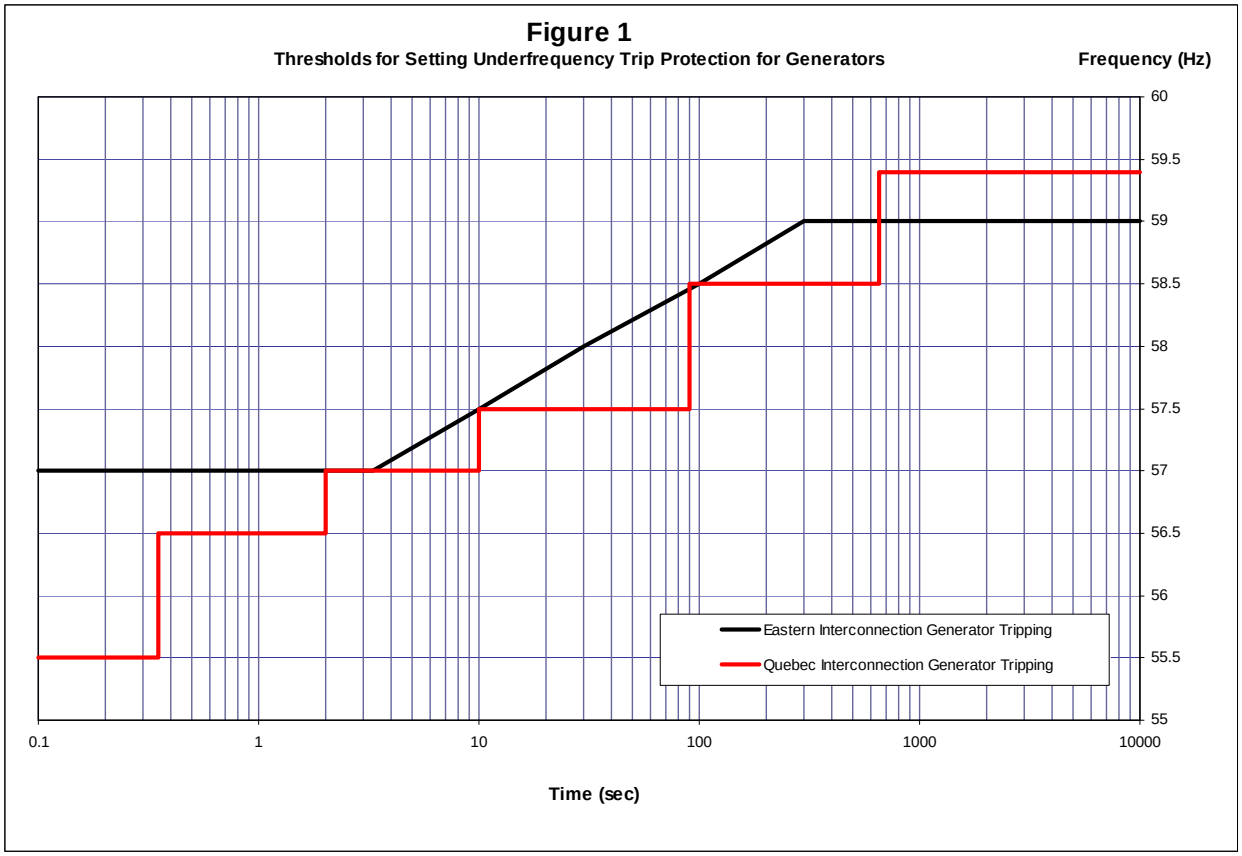
20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load

distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R22 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]


Figure 1
Thresholds for Setting Underfrequency Trip Protection for Generators
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
0.1
1
10
100
1000
10000
Time (sec)
Eastern Interconnection Generator Tripping
Quebec Interconnection Generator Tripping

C. Measures

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that

demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	**N/A**	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.
R2	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested

				information.
R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

		tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from providing two stages of UFLS.	solution is available that would allow the Distribution Provider or Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	N/A	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set

				an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
R8	N/A	N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8.
R9	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with

				Requirement R9.
R11	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R12	N/A	N/A	N/A	The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R13	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in

				Figure 1, except as otherwise exempted.
R14	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R15	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
R16	N/A	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of

			Requirement R16, Part 16.3.	Requirement R16, Part 16.3.
R17	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R18	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R19	N/A	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.	The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
R20	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.

R21	N/A	N/A	N/A	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
R22	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R23	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.

Version History

Version	Date	Action	Change Tracking
1	November 20, 2011	Region BOD Approval	
1	February 9, 2012	Adopted by Board of Trustees	
1	February 21, 2013	Order issued by FERC approving PRC-006-NPCC-1 (approval effective April 29, 2013)	

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting,

the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 4: Quebec Interconnection

	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times when above 60% of peak load..)	Mvar at peak	Total Nominal Operating Time (s) [2]
Threshold Stage 1	——	58.5	1000*	1000	0.30
Threshold Stage 2	——	58.0	800*	800	0.30
Threshold Stage 3	——	57.5	800	800	0.30
Threshold Stage 4	——	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	——	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

Hydro Québec TransÉnergie

Une division d'Hydro-Québec

August 26, 2016

VIA EMAIL

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Subject: PRC-006-3 Automatic UFLS Québec Variance – CEAP Phase 2

Following the end of the comment period for PRC-006-3 Quebec variance on August 22, 2016 it is our understanding that the next step in the process toward adoption would normally be the second phase of the Cost Effective Analysis Process (CEAP). Considering that only the Quebec Interconnection is concerned by the changes in PRC-006-3 and that the proposed revision does not incur any additional costs for us since it reflects current planning criteria, Hydro-Québec TransÉnergie proposes to waive phase 2 of the CEAP. Please let us know if this is acceptable to NPCC.

Regards.

Caroline Dupuis, eng.
Manager of Reliability Standards and Regulatory Compliance
Direction Normes de fiabilité et conformité réglementaire
Direction principale – Contrôle des mouvements d'énergie et exploitation du réseau
Hydro-Québec TransÉnergie

c.c. Sylvain Clermont (HQT Director of Reliability Standards and Regulatory Compliance)
Patrick Doyle (HQT manager of SRPI, Direction Planification)
Jeannette Gauthier (member of PRC-006-3 SDT)
Vincent Morissette (SME and member of PRC-006-3 SDT)
Si Truc Phan (RSC contact for PRC-006-3)
Ruida Shu (NPCC coordinator for PRC-006-3)

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-~~2~~ 3

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **Effective Date:**

   This standard is effective on the first day of the first calendar quarter six months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   PRC-006-2 was developed under Project 2008-02: Underfrequency Load Shedding (UFLS). The drafting team revised PRC-006-1 for the purpose of addressing the directive issued in FERC Order No. 763. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 FERC ¶ 61,098 (2012).

B. Requirements and Measures

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-32 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-32 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

- Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
- Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
- Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-32 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-32 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-32 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-32 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-32 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-32 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, per Requirement R9.

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, per Requirement R10.

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

R15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. *[VRF: High][Time Horizon: Long-term Planning]*

15.1. For UFLS design assessments performed under Requirement R4 or R5, the Corrective Action Plan shall be developed within the five-year time frame identified in Requirement R4.

15.2. For UFLS design assessments performed under Requirement R12, the Corrective Action Plan shall be developed within the two-year time frame identified in Requirement R12.

M15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall have a dated Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, that was developed within the time frame identified in Part 15.1 or 15.2.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, R14, and R15, Measures M1, M2, M3, M4, M5, M12, M14, and M15 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to	The Planning Coordinator identified an island(s) to serve	The Planning Coordinator identified an island(s) to serve

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				including notification of and a schedule for implementation by UFLS entities within its area
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.
R15	N/A	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, but failed to develop a Corrective Action Plan and a

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period of up to 1 month.	schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 1 month but not more than 2 months.	schedule for implementation by the UFLS entities within its area. OR The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 2 months.

D. Regional Variances

D.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

Rationale for Requirement D.A.3:

There are two modifications for requirement D.A.3 :

1. 25% Generation Deficiency : Since the Quebec Interconnection has no potential viable BES Island in underfrequency conditions, the largest generation deficiency scenarios are limited to extreme contingencies not already covered by RAS.

Based on Hydro-Québec TransÉnergie Transmission Planning requirements, the stability of the network shall be maintained for extreme contingencies using a case representing internal transfers not expected to be exceeded 25% of the time.

The Hydro-Québec TransÉnergie defense plan to cover these extreme contingencies includes two RAS (RPTC- generation rejection and remote load shedding -and TDST - a centralized UVLS) and the UFLS.

2. Frequency performance curve (attachment 1A) : Specific cases where a small generation deficiency using a peak case scenario with the minimum requirement of spinning reserve can lead to an acceptable frequency deviation in the Quebec Interconnection while stabilizing between the PRC-006-2 requirement (59.3 Hz) and the UFLS anti-stall threshold (59.0 Hz).

An increase of the anti-stall threshold to 59.3 Hz would correct this situation but would cause frequent load shedding of customers without any gain of system reliability. Therefore, it is preferable to lower the steady state frequency minimum value to 59.0 Hz.

The delay in the performance characteristics curve is harmonized between D.A.3 and R.3 to 60 seconds.

Rationale for Requirements D.A.3.3. and D.A.4:

The **Q**uebec Interconnection has its own definition of BES. In Quebec, the vast majority of BES generating plants/facilities are not directly connected to the BES. For simulations to take into account sufficient generating resources D.A.3.3 and D.A.4 need simply refer to BES generators, plants or facilities since these are listed in a Registry approved by Québec's Regulatory Body (Régie de l'Énergie).

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D.A.3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of

underfrequency conditions resulting from ~~an imbalance scenario, where an imbalance = [(load – actual generation output) / (load)], of up to 25 percent within the identified island(s)~~one of these extreme events:

- Loss of the entire capability of a generating station.
- Loss of all transmission circuits emanating from a generating station, switching station, substation or dc terminal.
- Loss of all transmission circuits on a common right-of-way.
- Three-phase fault with failure of a circuit breaker to operate and correct operation of a breaker failure protection system and its associated breakers.
- Three-phase fault on a circuit breaker, with normal fault clearing.
- The operation or partial operation of a RAS for an event or condition for which it was not intended to operate.

[VRF: High][Time Horizon: Long-term Planning]

D.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-32 - Attachment 1A, either for ~~30~~ 60 seconds or until a steady-state condition between 59.~~3~~ 0 Hz and 60.7 Hz is reached, and

D.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-32 - Attachment 1A, either for ~~30~~ 60 seconds or until a steady-state condition between 59.~~3~~ 0 Hz and 60.7 Hz is reached, and

D.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each Quebec BES generator bus and associated generator step-up transformer high-side bus ~~associated with each of the following:~~

~~**DA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES~~

~~**DA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES~~

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~~**DA.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.~~

M.D.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.A.3 Parts D.A.3.1 through D.A.3.3.

D.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

D.A.4.1 Underfrequency trip settings of individual generating units that are part of Quebec BES plants/facilities ~~with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES~~ that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-32 - Attachment 1A, and

D.A.4.2 Overfrequency trip settings of individual generating units that are part of Quebec BES plants/facilities ~~with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES~~ that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-32 - Attachment 1A, and

D.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement D.A.4 Parts D.A.4.1 through D.A.4.3.

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
DA3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts D.A.3.1, D.A.3.2, and D.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area.
DA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determineds through dynamic simulation whether the UFLS program design ~~meets~~ met the performance characteristics in Requirement D.A.3 but the simulation failed to include one	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determineds through dynamic simulation whether the UFLS program design ~~meets~~ met the performance characteristics in Requirement D.A.3 but the simulation failed to include two	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determineds through dynamic simulation whether the UFLS program design ~~meets~~ met the performance characteristics in Requirement D.A.3 but the simulation failed to include all of

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
		(1) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	(2) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	the items as specified in Parts D.A.4.1, D.A.4.2 and D.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3

D.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

D.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M.D.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement D.B.1.

D.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per D.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

D.B.2.1. Those islands selected by applying the criteria in Requirement D.B.1, and

D.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

M.D.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per D.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement D.B.2 Parts D.B.2.1 and D.B.2.2.

D.B.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

D.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-32 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-32 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

D.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

D.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

D.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M.D.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.B.3 Parts D.B.3.1 through D.B.3.3.

D.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

D.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-32 - Attachment 1.

D.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-32 - Attachment 1.

D.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation

above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-32 - Attachment 1.

D.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-32 — Attachment 1.

D.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-32 — Attachment 1.

D.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-32 — Attachment 1.

D.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement D.B.4 Parts D.B.4.1 through D.B.4.7.

D.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

D.B.11.1. The performance of the UFLS equipment,

D.B.11.2 The effectiveness of the UFLS program

M.D.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement D.B.11.

D.B.12. Each Planning Coordinator, in whose islanding event assessment (per D.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.D.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements D.B.12 and D.B.4 if UFLS program deficiencies are identified in D.B.11.

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.2	N/A	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.
D.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, and D.B.3.3 in simulations of underfrequency

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		conditions		conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
D.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include one (1) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include two (2) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include three (3) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	D.B.4.7.			OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2
D.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	D.B.11.1 and D.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	D.B.11.1 and D.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement D.B.11, Parts D.B.11.1 or D.B.11.2.	D.B.11.1 and D.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2.
D.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, failed to participate in and document a coordinated UFLS design assessment of the

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

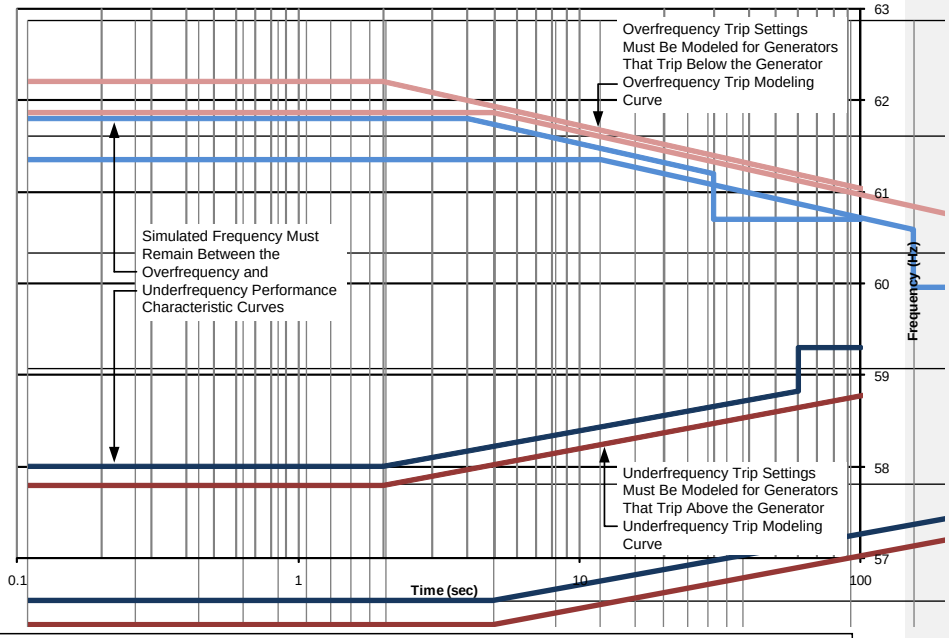
E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 25, 2010	Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.	
1	November 4, 2010	Adopted by the Board of Trustees	
1	May 7, 2012	FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)	
1	November 9, 2012	FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8.	
2	November 13, 2014	Adopted by the Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Revisions to existing Requirement R9 and R10 and addition of new Requirement R15.

PRC-006-~~2~~3 – Attachment 1

Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



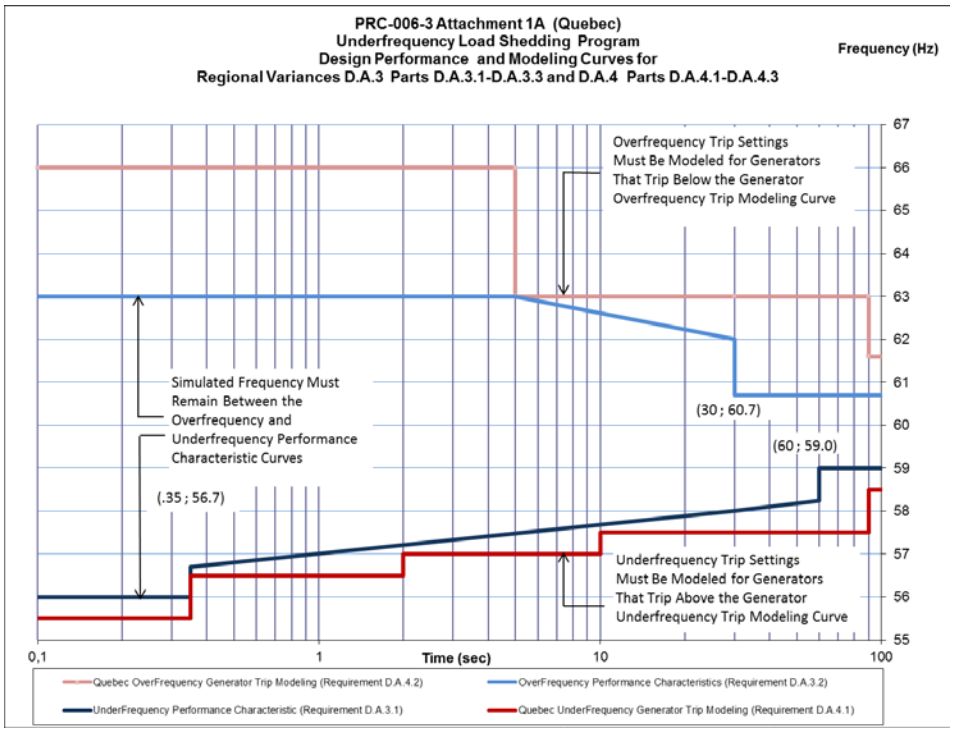
Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)
Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3)

Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling	Underfrequency Performance Characteristic

t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-3 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances D.A.3 Parts D.A.3.1-D.A.3.3 and D.A.4 Parts D.A.4.1-D.A.4.3
Frequency (Hz)
Overfrequency Trip Settings
Must Be Modeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(.35 ; 56.7)
(30 ; 60.7)
(60 ; 59.0)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip Modeling Curve
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56
55
0,1
1
Time (sec)
10
100
Quebec OverFrequency Generator Trip Modeling (Requirement D.A.4.2)
OverFrequency Performance Characteristics (Requirement D.A.3.2)
UnderFrequency Performance Characteristic (Requirement D.A.3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement D.A.4.1)

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R9:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a Planning Coordinator (PC) assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R10:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R15:

Requirement R15 was added in response to the directive from FERC Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. Requirement R15 addresses the FERC directive by making explicit that if deficiencies are identified as a result of an assessment, the PC shall develop a Corrective Action Plan and schedule for implementation by the UFLS entities.

A "Corrective Action Plan" is defined in the NERC Glossary of Terms as, "a list of actions and an associated timetable for implementation to remedy a specific problem." Thus, the Corrective Action Plan developed by the PC will identify the specific timeframe for an entity to implement corrections to remedy any deficiencies identified by the PC as a result of an assessment.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan (Draft for Comment)

Reliability Standard PRC-006-3 – Automatic Underfrequency Load Shedding

Revisions to Address Automatic Underfrequency Load Shedding (UFLS) Requirements for the Quebec Interconnection

Applicable Standard(s)

- PRC-006-3 – Automatic Underfrequency Load Shedding

Requested Retirement(s)

- PRC-006-2 – Automatic Underfrequency Load Shedding

Applicable Entities

- Planning Coordinators
- UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
    - Transmission Owners
    - Distribution Providers
- Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators

Background

The PRC-006-3 Regional Standard Drafting Team revised Section D.A of PRC-006-2, Regional Variance for the Quebec Interconnection to address two specific problems regarding UFLS requirements for the Quebec Interconnection :

1. To meet the PRC-006-2 59.3 Hz requirement for scenarios where Quebec has a small generation deficiency (between 4 and 6 percent), those scenarios would require modifications to the current settings of the UFLS program to the threshold of 59.3 Hz; this would cause unacceptable and frequent load shedding without any improvement to System reliability.

2. Because the Quebec Interconnection itself is an island with unique generation characteristics and RAS (SPS) applications, Section D.A.3 in PRC-006-2 needs to be revised to define a more accurate generation deficiency scenario applicable to the Quebec Interconnection.

The continent-wide Requirements and all other aspects of the standard remain unchanged from PRC-006-2.

Effective Date

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is one month after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is one month after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard PRC-006-2 shall be retired immediately prior to the effective date of PRC-006-3 in the particular jurisdiction in which the revised standard is becoming effective.

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE. OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

PRC-006-3 Automatic Underfrequency Load Shedding
Quebec Variance Comment Form

Background Information

PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance is developed to address two specific problems regarding UFLS requirements for the Quebec Interconnection:

1. To meet the PRC-006-2 59.3 Hz requirement for scenarios where Quebec has a small generation deficiency (between 4 and 6 percent) those scenarios would require modifications to the current settings of the UFLS program to the threshold of 59.3 Hz which would cause unacceptable and frequent load shedding without any improvement to system reliability.
2. Quebec Interconnection itself is an island with unique generation characteristics and RAS applications, Section D.A.3 in PRC-006-2 needs to be revised to define a more accurate generation deficiency scenario applicable to the Quebec Interconnection.
   The continent-wide PRC-006-2 requirements and all other aspects of the standard remain unchanged.

The comment period is open from July 7, 2016 through August 22, 2016.
Please submit your comments using this form and upload it to the NPCC website or provide your responses directly:
PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE. OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

Do you agree with the proposed revisions to Quebec Variance section of the PRC-006-2 Automatic Underfrequency Load Shedding?

Yes ☐

No ☐

Comments:

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

September 15, 2016

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	September 22, 2016 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://www.ferc.gov using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1030TH - MEETING

REGULAR MEETING

September 22, 2016

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD16-1-000	Agency Administrative Matters
A-2	AD16-7-000	Customer Matters, Reliability, Security and Market Operations
		ELECTRIC
E-1	RM01-8-000	Filing Requirements for Electric Utility Service Agreements
	RM10-12-000	Electricity Market Transparency Provisions of Section 220 of the Federal Power Act
	RM12-3-000	Revisions to Electric Quarterly Report Filing Process
	ER02-2001-000	Electric Quarterly Reports
E-2	RM16-21-000	Modifications to Commission Requirements for Review of Transactions under Section 203 of the Federal Power Act and Market-Based Rate Applications under Section 205 of the Federal Power Act
E-3	EL14-34-003	Public Service Commission of Wisconsin v. Midcontinent Independent System Operator, Inc.
	ER14-1242-005 ER14-1243-007 ER14-1724-003 ER14-1725-003 ER14-2176-003 ER14-2180-003 ER14-2860-002 ER14-2862-002 ER14-2952-002 ER14-2952-005	Midcontinent Independent System Operator, Inc.
	EL15-7-001	Michigan Public Service Commission v. Midcontinent Independent System Operator, Inc.
E-4	RM15-11-000	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events

E-5	RM16-13-000	Balancing Authority Control, Inadvertent Interchange, and Facility Interconnection Reliability Standards
E-6	RD16-6-000	North American Electric Reliability Corporation
E-7	ER12-1266-005 ER12-1266-006	Midcontinent Independent System Operator, Inc.
E-8	ER12-1265-005 ER12-1265-006	Midcontinent Independent System Operator, Inc.
E-9	ER16-197-002	Midcontinent Independent System Operator, Inc.
E-10	ER11-1844-001 ER11-1844-002	Midwest Independent Transmission System Operator, Inc.
E-11	ER14-1831-003	PJM Interconnection, L.L.C. Virginia Electric and Power Company
E-12	ER10-1350-006	Entergy Services, Inc.
E-13	ER10-1350-005	Entergy Services, Inc.
E-14	ER16-1169-000	Ameren Illinois Company
E-15	EC16-135-000	AEP Texas Central Company AEP Texas North Company AEP Utilities, Inc.
E-16	AC15-174-001	Duke Energy Carolinas, LLC Duke Energy Progress, LLC Duke Energy Florida, LLC
E-17	EL13-41-001	Occidental Chemical Corporation v. Midwest Independent Transmission System Operator, Inc.

GAS

G-1	OMITTED	
G-2	RP16-299-000 RP16-1137-000 (not consolidated)	Tuscarora Gas Transmission Company
G-3	RP16-302-000	Columbia Gulf Transmission, LLC
G-4	PR15-5-002 RP15-238-000	Washington Gas Light Company

G-5	RP16-1082-000	Columbia Gas Transmission, LLC

HYDRO

H-1	EL16-50-000	Percheron Power, LLC
H-2	P-12715-008	Fairlawn Hydroelectric Company, LLC
H-3	P-2212-049	Domtar Paper Company, LLC

CERTIFICATES

C-1	CP16-64-000	ANR Pipeline Company
C-2	CP16-78-000	Kinetica Deepwater Express, LLC

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through www.ferc.gov. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit www.CapitolConnection.org or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

September 2016
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its September 22, 2016 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These summaries are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

E-1, Press Release
E-2, Press Release
E-4, Press Release

FERC denies rehearing, grants clarification and acts on refund reports

E-3, *Public Service Commission of Wisconsin v. Midcontinent Independent System Operator, Inc.*, Docket No. EL14-34-003, *et al.* This order denies rehearing and grants, in part, clarification of the Commission's February 19, 2015 order addressing several proceedings related to the refund of previously allocated costs associated with the operation of System Support Resource Units under the MISO tariff. The order also finds that the refund reports submitted by MISO meet the Commission's requirements as stated in the Commission's May 3, 2016 order directing a refund report. However, the order directs MISO to suspend refunds for certain System Support Resource Units and file an updated refund report when the Commission issues an order on the Initial Decision in Docket No. ER14-1242-006, *et al*.

FERC proposes a rule

E-5, *Balancing Authority Control, Inadvertent Interchange, and Facility Interconnection Reliability Standards*, Docket No. RM16-13-000. The notice of proposed rulemaking proposes to approve Reliability Standards BAL-005-1 (Balancing Authority Control) and FAC-001-3 (Facility Interconnection Requirements) as submitted by North American Electric Reliability Corporation, and proposes to approve the retirement of Reliability Standard BAL-006-2 (Inadvertent Interchange).

FERC approves reliability standards

E-6, *North American Electric Reliability Corporation*, Docket No. RD16-6-000. This order approves two proposed Reliability Standards IRO-018-1 and TOP-010-1 submitted by the North American Electric Reliability Corporation that address real-time reliability monitoring and analysis capabilities of reliability coordinators, balancing authorities, and transmission operators.

FERC conditionally accepts compliance filings

E-7, *Midcontinent Independent System Operator, Inc.*, Docket Nos. ER12-1266-005 and ER12-1266-006. This order addresses outstanding compliance requirements primarily related to Order No. 745. The order conditionally accepts MISO's compliance filings. The order requires further compliance with respect to the allocation of costs associated with, among other issues, Demand Response Resource compensation across zones, allocation of these costs between day-ahead and real-time market participants, and tariff consistency issues.

FERC conditionally accepts compliance filing

E-8, *Midcontinent Independent System Operator, Inc.*, Docket Nos. ER12-1265-005 and ER12-1265-006. The order addresses outstanding compliance requirements primarily with respect to Order No. 719. This order accepts most of MISO's compliance filing and requires further compliance with respect to consumption baselines for Demand Response Resources and tariff consistency issues.

FERC grants clarification

E-9, *Midcontinent Independent System Operator, Inc*., Docket No. ER16-197-002. The order grants clarification of the Commission's December 30, 2015 order as it pertains to a potential ruling by the U.S. Internal Revenue Service (IRS). The order clarifies that, should the IRS rule that the proration methodology described in the U.S. Treasury regulations must continue to be applied to the originally projected Accumulated Deferred Income Tax balances in performing the annual formula rate true-up calculations, applicants are not estopped by the December 30 order from making a future filing with the Commission consistent with the IRS's direction.

FERC affirms, in part, and reverses, in part, an Initial Decision

E-10, *Midwest Independent Transmission System Operator, Inc.*, Docket Nos. ER11-1844-001 and ER11-1844-002. The order affirms in part, and reverses in part, certain determinations of the Presiding Administrative Law Judge (Presiding Judge), and it dismisses the remaining determinations of the Presiding Judge as moot. This proceeding

concerns a filing by MISO and International Transmission Company (ITC) proposing revisions to MISO's tariff to establish a methodology to recover costs of ITC's Phase Angle Regulating Transformers (PARs) located on the Michigan-Ontario, Canada border. The order finds that applicants have not demonstrated that their proposal to allocate costs of the PARS to entities outside of MISO is just and reasonable. The order also dismisses as moot requests for rehearing.

FERC denies rehearing

E-11, *PJM Interconnection, L.L.C.*, Docket No. ER14-1831-003. The order denies rehearing of the Commission's February 23, 2016 order that accepted Virginia Electric Power Company's (VEPCO) revision to its formula rate to change its methodology for calculating Accumulated Deferred Income Tax (ADIT) to accord with its IRS Private Letter Ruling (PLR). The order finds that VEPCO's approach to the true-up mechanism in its rate, used to reconcile the originally projected ADIT amounts with the actual ADIT amounts, is consistent with the PLR.

FERC accepts a compliance filing, subject to condition

E-12, *Entergy Services, Inc.*, Docket No. ER10-1350-006. The order accepts Entergy's compliance filing subject to the condition that Entergy submit a subsequent compliance filing that provides for interest on all bandwidth payments associated with Opinion No. 545, issued December 17, 2015. The order also requires Entergy to make other adjustments as required by the companion rehearing order being issued in Agenda Item E-13, Docket No. ER10-1350-005.

FERC denies rehearing request

E-13, *Entergy Services, Inc.*, Docket No. ER10-1350-005. This order denies rehearing of the Commission's order on the Initial Decision in the fourth bandwidth proceeding, Opinion No. 545, issued December 17, 2015. The order denies rehearing on all issues except for the issue of contra-securitization accumulated deferred income taxes (ADIT). The order requires removal of all securitized asset ADIT and contra-securitized asset ADIT for the 2009 test year. In addition, the order grants Entergy's requested clarification that the directive to Entergy to revise and resubmit its FERC Form No. 1s for the seven-month period from June 1, 2005 through December 31, 2005 is not intended to amend the bandwidth formula retroactively. The order also requires interest on all refunds required in this fourth bandwidth proceeding.

FERC denies a complaint

E-14, *Ameren Illinois Company*, Docket No. ER16-1169-000. This order denies a formal challenge submitted by Southwestern Electric Cooperative, Inc. and Southern Illinois

Power Cooperative protesting the annual informational formula rate update and true-up that was filed by Ameren Illinois as required by the formula rate protocols set forth in Attachment O-AIC of MISO's tariff.

FERC authorizes an internal corporate reorganization

E-15, *AEP Texas Central Company, AEP Texas North Company, AEP Utilities, Inc.*, Docket No. EC16-135-000. The order grants authorization for an internal corporate reorganization under which AEP Texas North and AEP Texas Central will merge into a single entity.

FERC affirms Chief Accountant's statement, denies rehearing

E-16, *Duke Energy Carolinas, LLC, et al.*, Docket No. AC15-174-001. The order denies requests for rehearing filed by three Duke Energy Corp. subsidiary operating companies (Duke Companies) of the Chief Accountant's February 12, 2016 letter order. That letter order granted Duke Companies' request for waiver of Commission regulations so that they may use the consolidated method of accounting instead of the equity method. That letter order, as relevant here, also noted the Commission's policy applicable to discounts on accounts receivable sold without recourse, *i.e.*, that such discounts are non-operating costs excluded from cost-of-service rates. The instant order affirms the Chief Accountant on this latter issue.

FERC denies rehearing request

E-17, *Occidental Chemical Corporation v. Midwest Independent Transmission System Operator, Inc.*, Docket No. EL13-41-001. This order denies Occidental's request for rehearing of the Commission's April 21, 2016 order. That order denied Occidental's complaint against MISO and Occidental's request for a declaratory order that MISO's plan for integrating qualifying facilities (QFs) in the Entergy operating companies' footprint violated QFs' rights under the Public Utility Regulatory Policies Act of 1978 and unduly discriminated against QFs in violation of the Federal Power Act.

FERC approves an uncontested settlement

G-2, *Tuscarora Gas Transmission Company*, Docket Nos. RP16-299-000 and RP16-1137-000. This order approves the July 15, 2016 uncontested settlement filed by Tuscarora, resolving all issues in the Natural Gas Act section 5 case brought by the Commission in Docket No. RP16-299-000. The order further approves Tuscarora's August 1, 2016 tariff filing in Docket No. RP16-1137-000, which implements the terms of its settlement.

FERC approves an uncontested settlement

G-3, *Columbia Gulf Transmission, LLC*, Docket No. RP16-302-000. This order approves the July 26, 2016 uncontested settlement filed by Columbia Gulf resolving all issues in the Natural Gas Act section 5 case brought by the Commission in Docket No. RP16-302-000. The order further requires Columbia Gulf to file revised tariff records within 30 days to reflect the Commission's action in this order.

FERC approves a settlement and related tariff records

G-4, *Washington Gas Light Company, LLC*, Docket Nos. PR15-5-002 and RP15-238-000. This order approves the offer of settlement and associated tariff records filed by Washington Gas Light Company on August 1, 2016, resolving all issues in these proceedings.

FERC approves a settlement

G-5, *Columbia Gas Transmission, LLC*, Docket No. RP16-1082-000. This order approves a settlement filed June 30, 2016 by Columbia that, among other things, would provide a more permanent framework for allocating costs from lost and unaccounted for gas volumes between transmission and gathering customers. The settlement sets the gathering retainage rate at 4 percent beginning March 1, 2017. The rate will increase by 0.5 percent each year until it reaches 6 percent. Additionally, Columbia agrees to hold annual meetings with customers. Settlement Article VII sets forth that the standard of review for changes to the settlement will be the "just and reasonable standard, and not the 'public interest' standard." The order finds that the settlement is uncontested and is fair, reasonable and in the public interest.

FERC denies petition for declaratory order

H-1, *Percheron Power, LLC*, Docket No. EL16-50-000. The order denies Percheron's petition for declaratory order requesting that the Commission find that it retains jurisdiction to authorize small conduit hydroelectric projects of 5 megawatts or less within U.S. Bureau of Reclamation's Columbia Basin Project. The order finds that the Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act withdrew the Commission's jurisdiction over new, small conduit hydropower development within the Columbia Basin Project, including the five particular sites in which Percheron had an interest in developing.

FERC grants a stay

H-2, *Fairlawn Hydroelectric Company, LLC*, Project No. 12715-008. This order grants Fairlawn Hydroelectric's request for a two-year stay of the commencement and

completion of construction deadlines for the Jennings Randolph Hydroelectric Project No. 12715, to be located at the U.S. Army Corps of Engineers' Jennings Randolph Dam and Lake, on the North Branch Potomac River in Garrett County, Maryland, and Mineral County, West Virginia.

FERC modifies, approves drawdown plan; grants a temporary license variance

H-3, *Domtar Paper Company, LLC*, Project No. 2212-049. This order grants Domtar Paper Company, licensee of the Rothschild Hydroelectric Project in Marathon County, Wisconsin, a temporary variance of Article 402 and approves a reservoir drawdown plan filed in accordance with Article 404 of its license in order to repair concrete deterioration at the waterline on the upstream side of the dam. The order concludes that the licensee's proposed drawdown schedule is reasonable and, although it would have a short-term effect on duck hunting and trapping season, would help minimize effects to the primary recreation season during the summer and to aquatic resources.

FERC authorizes compression facilities; denies rolled-in rate treatment

C-1, *ANR Pipeline Company*, Docket No. CP16-64-000. The order authorizes ANR to modify its existing Collierville Meter Station and construct and operate one new 4,700 horsepower compressor station and appurtenant facilities in Shelby County, Tennessee. The order denies the applicant's requested pre-determination of rolled-in rate treatment because the project revenues are less than the project's costs.

FERC authorizes abandonment of certain gas transmission facilities

C-2, *Kinetica Deepwater Express, LLC*, Docket No. CP16-78-000. The order authorizes Kinetica Deepwater Express (previously TC Offshore, LLC) to abandon by sale jurisdictional transmission facilities located in state and federal waters offshore Louisiana in the Gulf of Mexico, and onshore in the state of Louisiana.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Tie Line Relay Coordination

Primary Interest Groups
Reliability Coordinators (RCs)
Balancing Authorities (BAs)
Transmission Owners (TOs)
Transmission Operators (TOPs)

Problem Statement
A loss of three 345 kV transmission lines occurred when a phase A to ground fault on one line resulted in a misoperation that tripped a second line. As a result of these two lines tripping, the third line was open-ended due to the station bus configuration. The misoperation was the result of not coordinating relay communications equipment outages due to equipment failure between the different organizations.

Details
Prior to the event, equipment failure resulted in the permissive overreaching transfer trip (POTT) relay communication system being out of service at Substation 1. An initiating phase to ground fault on Line 1 between Substations 1 and 2 caused it to trip. Circuit breaker opening times in response to this fault resulted in a current reversal at Substation 2 on Line 2. This current reversal, in addition to receiver noise and the POTT communication system only being disabled at Substation 1, caused Line 2 to trip at Substation 2. A direct transfer trip then opened the Line 2 breakers at Substation 1. The configuration of the bus at Substation 2 resulted in Line 3 being open-ended after Lines 1 and 2 opened. This series of events caused a three-element loss for a fault that should have resulted in only a single element trip. See Diagrams 1, 2, and 3 for a visual representation.

During this event, the Line 2 POTT equipment at Substation 2 was still in service when it should have been taken out of service at the same time as the POTT equipment at Substation 1. This resulted in a false Line 2 POTT receive signal because of the noise in the receiver at Substation 2.

When the POTT equipment was removed from service at Substation 1, Entity 1 notified the primary control center at Entity 2; however, the Entity 2 primary control center did not notify their own relay department of this. In addition, Entity 1's policy did not require both ends of a POTT communication scheme to be disabled when one end was removed from service.

Corrective Actions
Entity 1 and Entity 2 outage coordination procedures (forced and scheduled) have been revised to incorporate internal and external review of work associated with relay systems on tie lines with other entities.

Both entities' primary control centers (PCC1 and PCC2) will provide their respective relay departments with periodic updates on the status of relay equipment at the remote terminals of tie lines.

Both PCCs have reviewed this event with their system operators and outage coordinators, stressing the importance of clear, accurate, and verified communications.

Entity 1 has reviewed its policy associated with work performed on POTT relay systems. Previously, the policy allowed removal of only one terminal of a POTT package during work on that end while the other end remained in service. As a result of this incident, Entity 1 will now, where applicable, remove the POTT relay system at both terminals when work is performed on the POTT relay system.

Lesson Learned

Entity 1 and Entity 2 will no longer rely on the applicable relay department initiating the work (planned and unplanned) to provide the PCCs with the appropriate information regarding the position of relay switches (i.e., on/off). Entity 1 and Entity 2 will now require that all relay work associated with tie lines be reviewed by both relay departments, regardless of which entity initiates the work.

When relay work is being conducted on any tie-line facilities (circuits that terminate in different entity substations), special care and review should be taken to make certain that the policies and maintenance practices of both entities are the same.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20160801
Date Published:	August 30, 2016
Category:	Relaying and Protection Systems

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

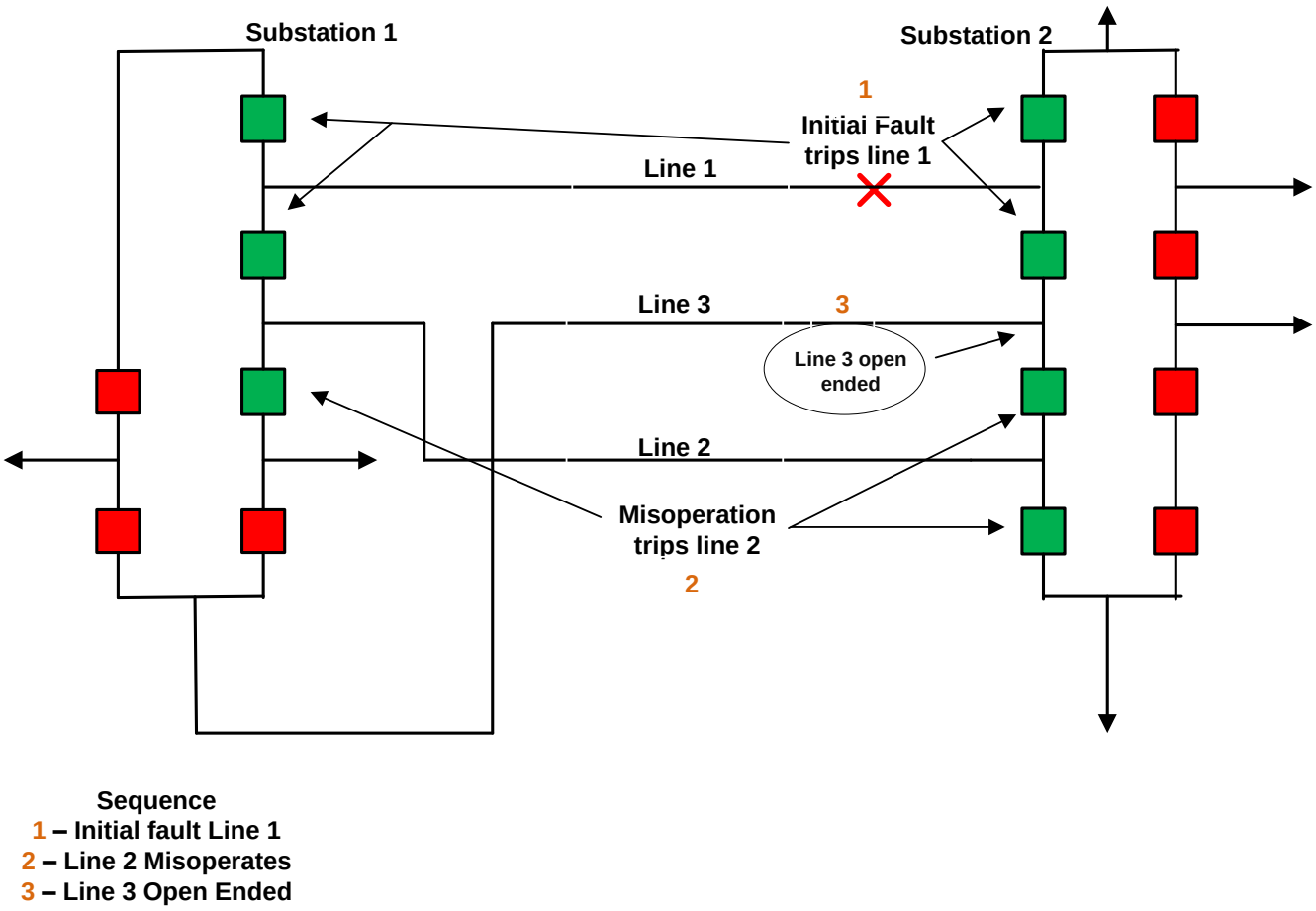
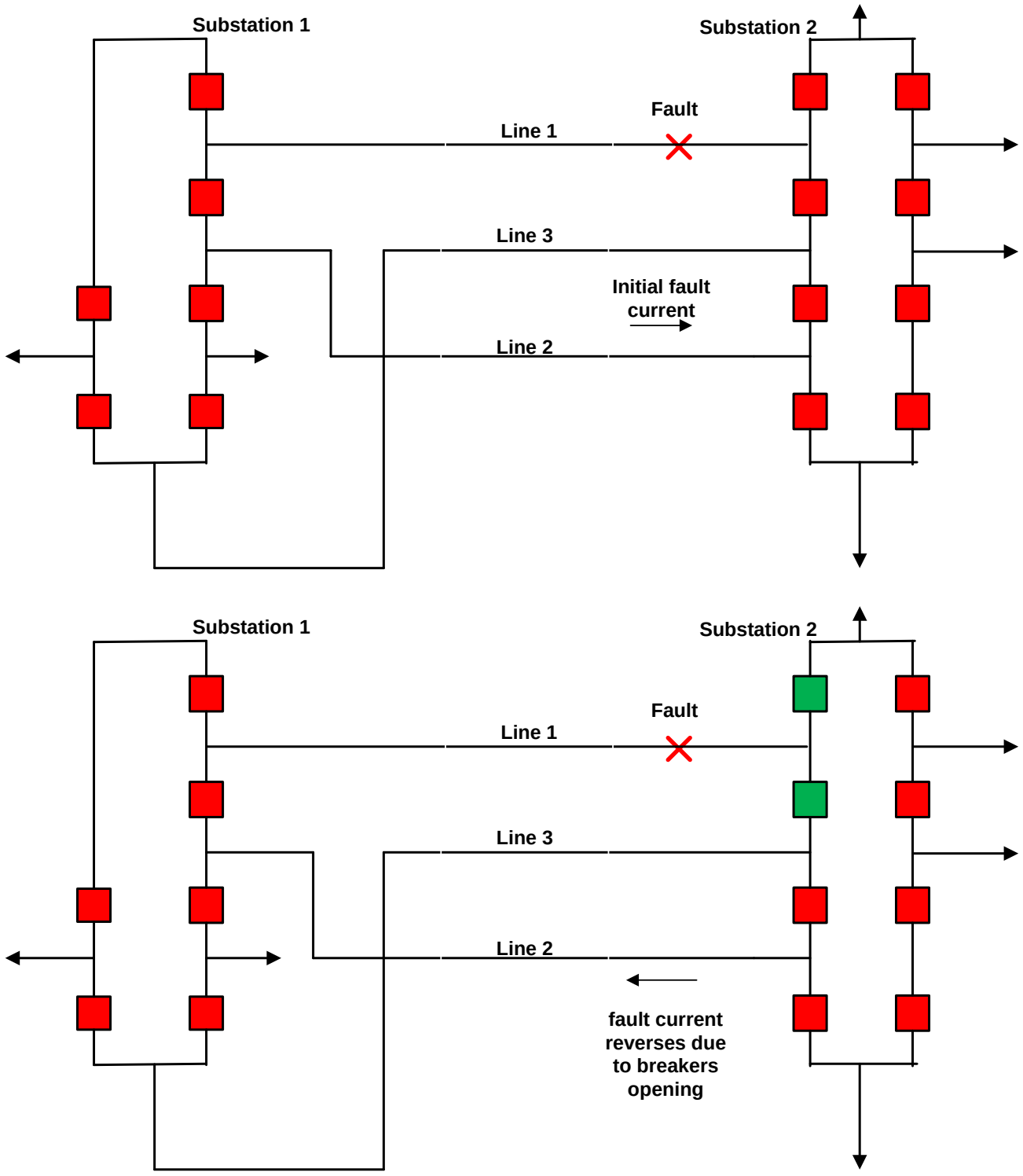


Diagram 1

Diagram shows the breaker operations for the initial Line 1 fault and associated Line 2 misoperation that resulted in Line 3 being open-ended



Diagrams 2 and 3 These diagrams show how current reversed in Line 2 due to breaker opening sequence for initial line fault

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2017 Business Plan and Budget

Draft 2

July 15, 2016

RELIABILITY | ACCOUNTABILITY






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About NERC

Overview

The North American Electric Reliability Corporation (NERC) is a not-for-profit entity organized under the New Jersey Nonprofit Corporation Act. NERC's mission is to improve and ensure the reliability of the Bulk Power System (BPS)[1] in North America. NERC's area of responsibility spans the continental United States and portions of Canada and Mexico. Entities under NERC's jurisdiction are the users, owners, and operators of the BPS—a system that serves the needs of over 340 million people, includes installed electricity production capacity of approximately 1,200 gigawatts, operates 475,000 miles of high-voltage transmission (100 kV and above), and is comprised of assets worth more than one trillion dollars.

Electric Reliability Organization (ERO)

The Federal Energy Regulatory Commission (FERC or Commission) certifies and has oversight of NERC as the electric reliability organization (ERO) within the United States to establish and enforce reliability standards for the U.S. portion of the BPS, pursuant to Section §215 of the Federal Power Act (§215).[2] As of June 18, 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and, for the most part, realized in Canada and Mexico.

International Relations

Prior to adoption of §215 in the United States, the Canadian provinces of Ontario (in 2002) and New Brunswick (in 2004) adopted all NERC reliability standards that were approved by the NERC Board of Trustees (Board) as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place, or NERC has memoranda of understanding with, provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC's standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are also mandatory. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transmission Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC reliability standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NEB has made reliability standards mandatory for international power lines between the U.S. and Canada.

In Mexico, the Comisión Federal de Electricidad has signed the Western Electricity Coordinating Council's (WECC's) reliability management system agreement, which applies only to Baja California Norte.

Membership and Governance

An 11-member Board of Trustees (the Board), comprised of 10 independent trustees and NERC's president and chief executive officer serving as the management trustee, governs NERC. The Board has formed several committees to facilitate oversight of the organization in the areas of finance and audit, governance and human resources, compliance, standards oversight and technology, nominations and, most recently, enterprise-wide risk.

[1] NERC's standards, compliance and enforcement activities are focused on the Bulk Electric System (BES), which is comprised of certain BPS facilities.

[2] ERO Enterprise Strategic Plan

Membership in NERC is open to any person or entity that has an interest in the reliability of the North American BES. Membership is voluntary and affords participants the opportunity to engage in the governance of the organization through election to the Member Representatives Committee (MRC).[3] More than 600 entities and individuals are members of NERC.

Scope of Oversight

As the international, multijurisdictional ERO in North America, NERC is authorized to:

- Propose, support the development of, monitor compliance with, and enforce mandatory reliability standards for the North American BPS, subject to regulatory oversight and approvals from FERC in the United States and applicable authorities in Canada;
- Conduct near-term and long-term reliability assessments of the North American BPS;
- Certify BPS operators as having and maintaining the necessary knowledge and skills to perform their reliability responsibilities;
- Maintain situational awareness of events and conditions that may threaten BPS reliability;
- Coordinate efforts to improve physical security and cybersecurity for the BPS of North America;
- Conduct detailed analyses and investigations of system disturbances and unusual events as well as measure ongoing system trends to determine root causes, uncover lessons learned, and issue relevant findings as advisories, recommendations, guidelines, and essential actions to the industry to mitigate and control risks to reliability; and
- Identify and prioritize risks to reliability and use a broad toolkit to mitigate and control risks to reliability, including the potential need for new or modified reliability standards, improved compliance monitoring and enforcement methods, or other initiatives.

Delegated Authorities

In executing its responsibility, NERC delegates certain authorities to eight regional reliability entities (Regional Entities or the Regions) to perform aspects of the ERO functions described through delegation agreements. FERC has approved delegation agreements between NERC and the eight Regional Entities (Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council, Inc. (NPCC), ReliabilityFirst, SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP RE), Texas Reliability Entity, Inc. (Texas RE), and the Western Electricity Coordinating Council (WECC)[4]). These agreements describe the authorities delegated and responsibilities assigned to the Regional Entities in the United States to address, among other things: (1) developing regional reliability standards, (2) monitoring compliance with and enforcement of mandatory reliability standards (both North American-wide and regional), (3) certifying registered entities and registering owners, operators, and users of the BES, (4) assessing reliability and analyzing performance, (5) training and education, (6) event analysis and reliability improvement, and (7) situation awareness and infrastructure security. NERC expects Regional Entities whose territories and geographic footprints extend into Canadian provinces and Mexico to perform equivalent functions in those jurisdictions.

[3] The Member Representatives Committee (MRC) comprises 28 voting representatives elected from the 12 membership sectors. The MRC elects the independent trustees and, along with the Board, votes on amendments to the Bylaws. The MRC also provides policy advice and recommendations to the Board on behalf of stakeholders with respect to annual budgets, business plans, and other matters pertinent to the purpose and operation of the organization.

[4] WECC has sub-delegated its Reliability Coordinator ("RC") function to Peak Reliability, which commenced operations and assumed the RC function within the WECC footprint on January 2, 2014.

ERO Enterprise Operating Model

The collective network of leadership, experience, judgment, skills, and technologies shared among NERC and the eight Regional Entities is referred to as the ERO Enterprise (the Enterprise). In 2014, a common operating model, Improving Coordinated Operations across the ERO Enterprise,[5] was developed to define how NERC and the Regional Entities achieve excellence in the oversight and execution of statutory functions by collaborating to mitigate reliability risks. The model also defines the division of the roles and responsibilities for NERC and the Regional Entities to efficiently and effectively execute services performed as the collective Enterprise. In 2015, implementation of this model progressed with oversight plans developed for Compliance Monitoring and Enforcement programs, and Registration. Further, NERC and the Regional Entities deepened its coordination activities to identify, prioritize and address risks to reliability.

NERC has unique responsibilities within the Enterprise to design the oversight of program areas; develop operational oversight and leadership; set qualifications and expectations for the performance of delegated activities; and assess, train, and give feedback to corresponding regional programs. NERC also reviews and provides input to the annual Regional Entity business plans and budgets, including but not limited to review of resource allocations, staffing capacity assessments, and program performance assessments. NERC input and review occurs before regional board approval.

Similarly, the Regional Entities have a mirrored set of responsibilities that include being responsive to the design of the operational model, providing input into the overall development of each ERO program area, providing training and development to meet ERO qualifications, being receptive to feedback from the ERO, and making responsive adjustments. Regional Entities also have an obligation to meet professional standards of independence and objectivity, and provide the best available expertise for addressing risks.

With due recognition and awareness of the distinction between individual roles, responsibilities, and corporate status, NERC and the Regional Entities are continually refining their individual and collective operating and governance practices in support of an agreed-upon set of strategic goals and objectives that are designed to ensure the ERO fulfills its statutory obligations.

Statutory and Regulatory Background

NERC's authority as the ERO in the United States is based on Section 215 of the Federal Power Act, as added by the Energy Policy Act of 2005,[6] and the Commission's regulations and orders issued pursuant to Section 215. In Canada, NERC's authorities are established by the memoranda of understanding and regulations previously mentioned.

Funding

Section 215 of the Federal Power Act and the Commission's regulations specify procedures for NERC's funding in the United States. NERC's annual business plan and budget is subject to Commission approval in the United States. Once approved, NERC's annual funding is provided through assessments to load-serving entities. These assessments are allocated on a net-energy-for-load (NEL) basis. Equivalent funding mechanisms are provided in Canada, subject to the specific laws and regulations of each province.

The Regional Entities' funding requirements are addressed separately in their respective business plans and budgets, which must be reviewed and approved by NERC and FERC in the United States. Assessments for the Regional Entity budgets are included in the overall NERC assessments to load-serving entities.

[5] Improving Coordinated Operations Across the ERO Enterprise

[6] This was codified in section 215 of the Federal Power Act, 16 United States C. 824o.

Introduction and Executive Summary

TOTAL RESOURCES (in whole dollars)	2017 Budget	U.S.	Canada	Mexico
Statutory FTEs	189.88			
Non-statutory FTEs				
Total FTEs	189.88			
Statutory Expenses	$ 66,921,632			
Non-Statutory Expenses	$ -			
Total Expenses	$ 66,921,632			
Statutory Inc (Dec) in Fixed Assets	$ 2,680,543			
Non-Statutory Inc (Dec) in Fixed Assets	$ -			
Total Inc (Dec) in Fixed Assets	$ 2,680,543			
Statutory Change in Reserves Requirement	$ (69,598)			
Non-Statutory Change in Reserves Requirement				
Total Working Capital Requirement	$ (69,598)			
Proceeds from Financing Activities	$ 19,083			
Total Statutory Funding Requirement	$ 69,551,660			
Total Non-Statutory Funding Requirement	$ -			
Total Funding Requirement	$ 69,551,660			
	TOTAL	**US**	**CANADA**	**MEXICO**
Statutory Funding Assessments	$ 59,856,314	$ 54,326,337	$ 5,353,026	$ 176,951
Non-Statutory Fees				
NEL	4,514,633,135	3,983,687,261	518,227,758	12,718,116
NEL%	100.00%	88.24%	11.48%	0.28%

Strategic Goals and Metrics

The ERO Enterprise strategic plan and framework informed by the following activities completed in 2015: (1) NERC's State of Reliability Report; (2) the Reliability Issues Steering Committee's (RISC's) ERO Reliability Risk Priorities Report and Supplemental Technical Summary, which includes identified risk profiles; and (3) input from the NERC Board and Regional Entity Boards. In 2015, these inputs were used by ERO Enterprise leadership to:

- **Update ERO Enterprise Longer-term Strategic Planning Considerations** – The ERO Enterprise makes any necessary adjustments to its longer-term strategic planning considerations, which takes into consideration Bulk Electric System (BES) reliability issues over a 5 to 15-year planning horizon.
- **Update the Three-year ERO Enterprise Strategic Goals** – The ERO Enterprise makes any necessary adjustments to its strategic goals for the next three years.
- **Develop Annual ERO Enterprise Metrics** – The ERO Enterprise develops annual metrics to measure the ERO Enterprise's progress in attaining the strategic goals.
- **Develop Annual Business Plans and Budgets** – Working collaboratively, NERC and each of the Regional Entities develop annual business plans and budgets (BP&Bs) that reflect the resources necessary to support achievement of the goals set forth in the strategic plan.

Evolving Reliability Risks

Over the past five years, NERC has transformed its activities towards being more risk-based, ensuring that the right activities are focused on the most pertinent risks to the reliable operation of the bulk power system. The RISC is an advisory committee to the Board, providing key insights, priorities, and high-level leadership for issues of strategic importance to BPS reliability. The 2015 RISC report presents the results of their continued work to define and prioritize risks, and offer recommendations to the Board to inform the development of NERC's risk strategy. The report recommendations are considered as the Strategic Plan, Goals and supporting activities are updated for the coming years. In 2015, the RISC recommended a high level of focus and priority in the following areas:

- **Regulatory Uncertainty (Markets, states, and federal/provincial)**
  These risks arise where the impacts from regulatory initiatives are uncertain in their extent, timing, and potential reliability considerations. These uncertainties are accentuated by the interplay among these three arenas, each of which reflects policy, regulatory, and legislative dimensions which may not include sufficient reliability coordination.

- **Resources (Changing resource mix, inadequate planning coordination, and ineffective resource planning)**
  This set of evolving risks reflects interdependent aspects from the continued and accelerated rapid transformation of the resource mix. As part of the increased and accelerated integration of new types of variable, renewable, and distributed energy resources, planners must ensure that sufficient ERSs and operator flexibility are available to maintain reliability.

- **Resiliency: Cyber security**
  These risks reflect aspects of resilience related to potential cyber disruptions of the BPS. As cyber aspects evolve, they require more assertive and flexible approaches to provide adequate assurances of reliability.

2016-2019 Strategic Goals

The ERO Enterprise has five strategic goals, adopted by the NERC Board in November 2015, enabling it to successfully carry out its mission as further described in the Strategic Plan. For each goal, a detailed description is provided, activities that contribute to its success, and additional information about the allocation of NERC's resources toward their achievement are noted below. The associated metrics in support of these goals have been approved for 2016[7]; updated strategic goals and associated metrics will be finalized later in 2016 for the 2017 year, with opportunities for stakeholder feedback prior to their approval. At this time it is not anticipated that these updates will have a material impact on NERC's overall budget or resource allocation among operating areas for 2017. However, the updates may potentially affect priorities and workload within particular departments and will inform resource planning and allocation for the 2018 budget year.

Goal 1
Timely and Risk-Responsive Reliability Standards

Reliability standards establish threshold requirements for assuring the BES is planned, operated, and maintained to minimize risks of cascading failures, avoid damage to major equipment, or limit interruptions of bulk electric supply. Reliability standards are clear, timely, responsive to reliability risks and cost-effective.

Contributing Activities

- Conduct periodic reviews and assessment of whether the reliability standard is properly structured for emerging risks.
- Assess reliability standards compared to the BES risk profile; address the most important unmitigated risks, including applicable high-impact, low-frequency risks.
- Develop and implement ERO Enterprise feedback loops to identify and address gaps or ambiguities in reliability standards, including the evaluation of significant BES events (including all category 3 and above).
- Develop and implement procedures for assessing the cost impact of reliability standards.

Goal 2
Objective and Risk-informed Compliance Monitoring, Enforcement, and Organization Certification and Registration

The ERO Enterprise is a strong enforcement authority that is independent, without conflict of interest, objective, and fair, and promotes a culture of reliability excellence through risk-informed compliance monitoring, enforcement, certification, and registration.

Contributing Activities

- Consistently register and deregister entities based on risk to the BES and the BES definition.
- Evaluate the certification program for effectiveness and implement consistently across the ERO Enterprise.
- Develop Compliance Oversight Plans for registered entities that address the relevant risks.
- Focus Compliance Monitoring and Enforcement activities on the most significant risks to the BES.
- Process non-compliance using the appropriate method, considering the risk to the BES.

[7] See 2016 ERO Enterprise and Corporate Metrics for details.

- Implement Compliance Monitoring and Enforcement consistently, timely, and transparently to industry.

Goal 3
Identification and Mitigation of Significant Current Risks to Reliability

The ERO Enterprise identifies the most significant risks to reliability, provides assurance for mitigating reliability risks, and promotes a culture of reliability excellence. The ERO Enterprise supports the Electricity Information Sharing and Analysis Center (E-ISAC), the Cybersecurity Risk Information Sharing Program (CRISP), reliability assessments, situational awareness, and physical security and cybersecurity preparedness.

Contributing Activities

- Perform reliability data-grounded analyses and sustain independent, technical assessments of proposed regulatory rules or proposed statutes (state, provincial, or federal) as well as significant market rules to determine potential impacts to reliability.
- Maintain a BES risk profile to prioritize and rank reliability risks.
- Develop project plans and business case assessments for high-priority risks including cost and practicality of assessment; implement or facilitate initiatives to address high-priority risks.
- Integrate risk data sources, such as event analysis, Transmission Availability Data System, Generating Availability Data System, and relay misoperations as well as other occurrences (e.g., AC equipment failures) to provide lessons learned, recommendations, identified risks, and their mitigation to promote reliability.
- Analyze system performance and significant events (e.g., sampling of Category 2 events in addition to assessing all Category 3 and above) to identify gaps in reliability standards, compliance effectiveness, registration, and risk controls effectiveness, as well as the development of lessons learned or other information sharing activities that promote BES reliability.
- Enhance communications among the E-ISAC, the Telecommunications Information Sharing and Analysis Center, and Natural Gas Information Sharing and Analysis Center.
- Facilitate the availability, sharing and value of physical security and cybersecurity threat and vulnerability information, analytics, and analysis.

Goal 4
Identification and Assessment of Emerging Risks to Reliability

The ERO Enterprise identifies, evaluates, studies and independently assesses emerging risks to reliability.

Contributing Activities

- Develop sufficiency/adequacy guidelines for essential reliability services (ERS) including emerging risks. Include consideration of the range of reliability attributes based on a diverse resource mix and load behavior, such as ramping, fast regulation, reserve services, and interdependent sector performance.
- Enhance reliability assessments to reflect changing resource mix behavior, including distributed energy resources and ERS, with probabilistic approaches, considering the variable and energy-limited nature of the resource shifts.
- Evaluate the impacts on BES recovery and restoration plans including consideration of distributed resources.

Goal 5
Effective, Efficient, and Collaborative ERO Enterprise

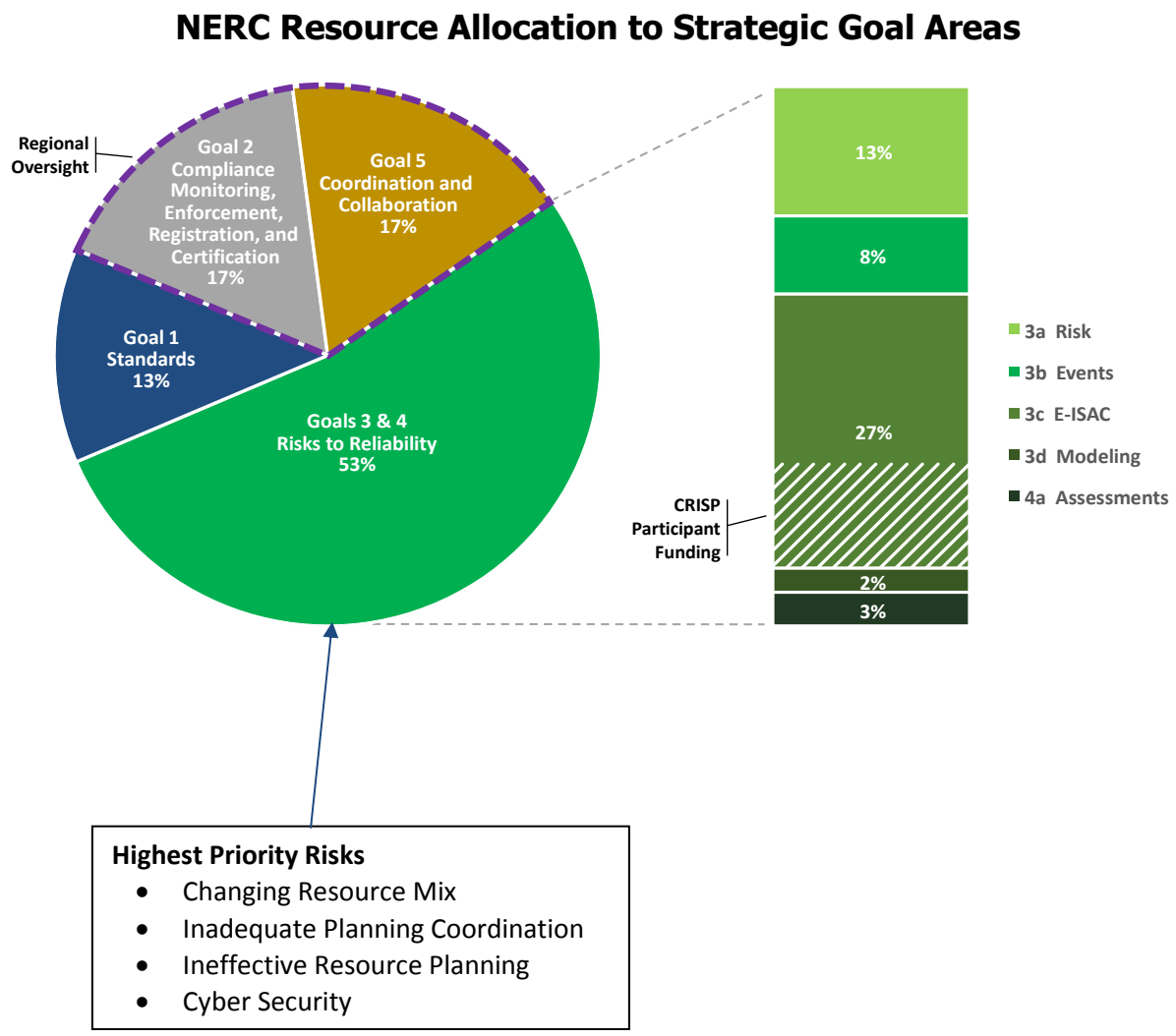
The ERO Enterprise improves transparency, consistency, quality, efficiencies, cost-effectiveness, and timeliness of results and operates as a collaborative enterprise.

Contributing Activities

- Articulate a shared vision of reliability excellence and support and inspire stakeholders continent-wide, including in international jurisdictions, in working to attain that vision.
- Engage the support and expertise of stakeholders in prioritizing and resourcing reliability initiatives.
- Communicate expectations clearly and foster collaboration to deliver important results in advancing system reliability.
- Acquire, engage, and retain highly qualified talent with requisite technical expertise to execute the ERO Enterprise's statutory functions.
- Understand and manage ERO Enterprise internal risks.
- Processes and procedures are consistent, effective, and efficient.
- Clearly delineate ERO Enterprise roles and responsibilities using the ERO Enterprise Operating Model to mature the collaborative processes.

Allocation of NERC Resources to Strategic Goals and Risk Priorities

The charts below provide an overview of the allocation of NERC's 2017 resources associated with each strategic goal, as well as the RISC priorities. Using FTEs and funding as a guide, the charts reflect the relative amount of total NERC resources (people and dollars) focused on supporting each of the five strategic goals noted above. Obviously many NERC departments work on multiple activities that further multiple goals, and precision in forecasting all activities supporting each goal is not practical. However, these charts provide a general picture regarding how the company's resources are allocated.



Ongoing Focus on Cost Control and Efficiency

NERC and the Regional Entities continue to work collaboratively to improve efficiency, evaluate resources, and leverage combined skillsets to improve various ERO Enterprise activities and control costs. This collaboration and the resulting efficiencies can be found in a number of areas, including but not limited to:

- **ERO Enterprise IT Investments:** NERC and the Regional Entities, working collaboratively with oversight of NERC's Standards Oversight and Technology Committee, have developed a long-term enterprise information technology program resulting in a number of enterprise tools. The goals is to enhance operations and reduce costs at the regional and registered entity level. For example, enterprise tools have helped and will further facilitate efficiency of registration and data submittals, improved consistency in registered entity resources devoted to compliance, and improved overall reliability through information sharing on Events Analysis and Situation Awareness.
- **Enforcement**: NERC has worked closely with Regional Entities to streamline enforcement staff in connection with the development of more efficient and risk-based enforcement mechanisms.
- **Standards:** As standards development has matured, NERC management has reduced standards staff allocations towards more critical activities like cyber security and analytical capabilities.
- **Legal:** As a result of the aforementioned efficiencies and the maturity of NERC's and ERO Enterprise's business processes, the legal department has reduced its resource requirements, reallocating limited resources to more critical priorities without impacting the company's overall staffing requirements.
- **Forums**: As further described in the quarterly forum reports to the NERC Board of Trustees, NERC and the Regional Entities continue to leverage the transmission and generation forums to jointly address risks to reliability to mitigate their impacts on the reliable operation of the BES.
- **Industry:** The Enterprise continues to collaborate with, and rely on, industry resources and expertise through the various standing committees[8], working groups and task forces which are critical to both identifying and supporting key initiatives and priorities.

2017 Key Business Planning Assumptions

As part of the annual business planning process, NERC and the Regional Entities developed a set of common business planning assumptions supporting the development their respective business plans and budgets. The Regional Entities used these assumptions to evaluate their projected workloads and determine resource levels and allocation required to complete necessary tasks and meet the obligations of their Regional Delegation Agreements. These common business planning assumptions are set forth in Exhibit A.

Application of Section 215 Criteria

In its order approving NERC's *2013 Business Plan and Budget*, FERC required NERC to establish criteria for determining whether its proposed activities are eligible for funding under Section 215. In an order dated April 19, 2013, FERC approved NERC's proposed criteria, with certain modifications.[9] Exhibit B summarizes the major activities NERC proposes to undertake in 2017 and the approved Section 215 criteria applicable to such activities.

[8] For further information please see the quarterly reports to the NERC Board of Trustees by the NERC Operating, Planning, Critical Information Protection, Standards and Compliance Certification Committees.

[9] North American Electric Reliability Corporation, Order on Compliance, 143 FERC ¶ 61,052 (2013).

Overview of 2017 Budget and Funding Requirements

NERC's 2017 combined expense and fixed asset (capital) budget is approximately $69.6M, which represents an increase of approximately $2.4M (3.6%) from the 2016 budget. Total expenses are increasing approximately $1.0M (1.5%) over 2016. The total fixed asset (capital) budget, excluding depreciation,[10] is approximately $4.4M, an increase of $461k over 2016. Approximately $8.3M (11.9%) of NERC's 2017 budget is related to CRISP. In the absence of CRISP, the 2017 budget would also increase $2.1M (3.5%) over 2016. As further explained in Section A – Electricity Information Sharing and Analysis Center (E-ISAC), the majority of the NERC CRISP budget will be funded by participating utilities, with only a small portion funded through assessments. A comparative statement of activities presenting NERC's 2017 budget with and without CRISP is set forth later in this section.

Without the release of funds from the Assessment Stabilization Reserve to offset assessments (as discussed below), NERC's total average assessments would increase $3.9M (6.8%) over 2016. One of the primary differences between NERC's current 2017 budget increase of 3.6% and the 6.8% 2017 assessment increase (unadjusted) results from eliminating the one-time application of 2016 penalty funds used to offset U.S. assessments in 2017. This loss of penalty offsets will not impact Canadian or Mexican assessments since U.S. penalty funds are only used to reduce U.S. assessments.[11] Other factors contributing to this difference include debt assumptions and projected reserve requirements, all of which impact assessments in the United States, Canada, and Mexico.

As a long-term strategy to stabilize assessments and align budget and assessment increases more closely, NERC has undertaken a multi-year strategy to manage assessment increases. Under the previous policy for releasing penalty funds, NERC was required to recognize those penalties in subsequent budget periods to offset assessment billings. In February 2015, NERC's Board approved an amendment to the company's Working Capital and Operating Reserve Policy. [12] Among the approved changes to this policy was the creation of an Assessment Stabilization Reserve.[13] This reserve was established to address the strategic goal of more closely aligning budget and assessment increases and provide resources to better manage year-to-year assessment increases. The eventual goal is to narrow the gap between annual percentage changes in NERC's budget and assessments that results from year-to-year changes in penalty collections.

Management proposes an overall average 2017 assessment increase of 4.9%, which includes the release of $1.1M from the Assessment Stabilization Reserves to offset U.S. assessments. The allocation of assessments to Canadian entities will depend on the final determination and allocation of certain compliance and enforcement costs to Canadian entities pursuant to NERC's policy on the allocation of compliance costs.[14]

[10] NERC and the Regional Entities budget Depreciation as an Operating Expense with an equal and offsetting credit against budgeted Fixed Asset Additions; as a result, the budgets do not include depreciation in the funding requirements.

[11] Accounting, Financial Statement and Budgetary Treatment of Penalties Imposed and Received for Violations of reliability standards, December 8, 2008 and as amended August 15, 2013

[12] NERC's Working Capital and Operating Reserve Policy. NERC filed a petition with FERC on March 6, 2015 for approval of this policy; the Commission conditionally approved the revised policy in an order issued June 18, 2015, in Docket No. RR15-8-000. *North American Electric Reliability Corporation, Order Conditionally Accepting Revisions to Working Capital and Operating Reserve Policy*, 151 FERC ¶ 61,225 (2015)

[13] In accordance with the approved policy, this reserve may be funded with penalty funds and surplus operating reserves. The actual amount of the contribution, as well as releases from the fund to reduce assessments, is determined annually as part of NERC's business plan and budget process, including the recommendation by the Board's Finance and Audit Committee and both Board and FERC approval.

[14] Expanded Policy on allocation of Certain Compliance and Enforcement Costs, July 29, 2008.

The following table provides a high-level year-over-year comparison of the major categories of expenses, total budget, and FTEs.

Statement of Activities and Fixed Assets Expenditures 2016 and 2017 Budgets
STATUTORY

	2016 Budget	2016 Projection	Projection v 2016 Budget Over(Under)	2017 Budget	2017 Budget v 2016 Budget Over (Under)	% Over (Under)
Funding						
NERC Assessments	$ 57,081,445	$ 57,081,445	$ (0)	$ 59,856,314	$ 2,774,868	4.9%
Penalty Sanctions	1,439,000	1,439,000	-	1,100,000	(339,000)	
Third-Party Funding (CRISP)	6,830,738	7,335,757	505,019	6,990,447	159,709	
Testing Fees	1,867,972	1,867,972	-	1,921,900	53,928	
Services & Software	50,000	50,000	-	50,000	-	
Workshops	230,000	269,201	39,201	230,000	-	
Interest	3,000	35,898	32,898	3,000	-	
Total Funding (A)	**$ 67,502,155**	**$ 68,079,475**	**$ 577,320**	**$ 70,151,660**	**$ 2,649,505**	**3.9%**
Expenses						
Personnel Expenses	$ 37,283,807	$ 37,288,967	$ 5,161	$ 38,641,331	$ 1,357,525	3.6%
Meeting Expenses	3,620,286	3,646,564	26,278	3,372,886	(247,400)	-6.8%
Operating Expenses	24,903,515	25,947,939	1,044,424	24,800,690	(102,825)	-0.4%
Other Non-Operating Expenses	110,000	100,668	(9,332)	106,725	(3,275)	-3.0%
Total Expenses	**$ 65,917,608**	**$ 66,984,139**	**$ 1,066,531**	**$ 66,921,632**	**$ 1,004,024**	**1.5%**
Fixed Assets						
Depreciation	$ (2,641,943)	$ (2,558,606)	$ 83,336	$ (1,691,457)	$ 950,486	
Computer & Software CapEx	2,447,000	2,362,402	(84,598)	2,572,000	125,000	
Equipment CapEx	1,464,000	1,545,797	81,797	1,800,000	336,000	
Inc(Dec) in Fixed Assets	**1,269,057**	**1,349,593**	**80,535**	**2,680,543**	**1,411,486**	
TOTAL BUDGET	**$ 67,186,665**	**$ 68,333,732**	**$ 1,147,067**	**$ 69,602,175**	**$ 2,415,510**	**3.6%**
FTEs	**192.5**	**188.6**	**(3.9)**	**189.9**	**(2.6)**	**-1.3%**

NERC's 2017 budget and funding requirements reflect the resources necessary to support achievement of the goals and objectives set forth in the Strategic Plan. The 2017 budget is comprised of both operating and capital (fixed asset) costs. Operating costs generally include personnel, consulting, office space, software licensing, third-party data management, and communications and other customary services to support office operations. Fixed asset (capital) costs primarily reflect investments in equipment and software to support operations, including investments in the development of software applications and infrastructure to facilitate improved business processes and efficiency.

Key Budget Assumptions

Key assumptions used in the development of NERC's 2017 budget include the following:

- Maintaining FTEs at a similar level as 2016. Management routinely reviews resource allocation to ensure that the appropriate amount and type of resources are being dedicated to key priorities and activities. As operations in some areas become more efficient and/or major initiatives are completed, resources are redeployed to priority areas. For example, as work on reliability standards reduced as regulatory obligations were addressed, it was possible to reallocate some of those resources to support additional compliance assurance, reliability risk assessment, and security needs without increasing the company's overall FTE budget.
- Applying a 6.0% reduction to FTEs (vacancy rate) to account for attrition and hiring delays. This assumption is based on a review and analysis of historic attrition and vacancy rates, as well as the time it takes to recruit and onboard new staff. This is reduction in the historical vacancy rate

assumptions and reflects the ongoing management focus on recruiting and retaining appropriate resources.

- Market-based compensation for personnel. Executive and staff compensation and benefits are established based on guidelines established by NERC's Corporate Governance and Human Resources Committee and comprehensive market compensation and benefit information provided by a leading nationally recognized compensation and benefits consulting firm, as well as other available data. An updated market study was completed in late 2015 under the oversight of NERC's Corporate Governance and Human Resources Committee.
- Anticipating market increases in medical and dental benefit plan costs. Medical and dental premium cost estimates are based on market data provided by the company's benefits consultant. Current 2017 budget estimates are in the upper end of the range provided by NERC's benefits consultant. This estimate will continue to be evaluated prior to finalization of the final recommended 2017 budget. No other changes to retirement or other benefit plans have been assumed for 2017.
- In 2015, the Electricity Subsector Coordinating Council (ESCC)[15] presented its recommendations resulting from a review of the E-ISAC operations performed that year. These recommendations included a request to evaluate and potentially enhance the user interface and underlying functionality of the E-ISAC portal. In 2015, the ESCC established a Member Executive Committee (MEC) to provide guidance with respect to various E-ISAC matters, including improvements to the E-ISAC portal. As part of an approved 2016 work plan, the E-ISAC staff worked closely with the MEC to develop a business case and funding estimates for these improvements. A power point presentation summarizing the business case, funding estimate and additional detail regarding the portal improvement project is attached as Exhibit F.

  The 2017 E-ISAC budget includes $1M for the portal enhancements ($250,000 of which is allocated to CRISP) for the portal project. The annual impact of the proposed $1M investment on assessments will be approximately $250,000 since projects of this nature are typically financed through NERC's capital financing program and funded over a three year period. The MEC has provided written comments [found here] in support of this investment.
- Meeting and travel expenses are being held flat based on a review of 2015 and 2016 costs. The company has undertaken a number of significant efforts over the past several years to reduce travel and meeting expenses. For example, the company has also worked closely with Regional Entities to share meeting space where possible, which has helped reduce meeting costs.
- Contractor and consulting expenses are developed on a department-by-department basis and reflect both known and anticipated expenses, based on historic and current information.

[15] The Electricity Subsector Coordinating Council (ESCC) serves as the principal liaison between the federal government and the electric power sector, with the mission of coordinating efforts to prepare for, and respond to, national-level disasters or threats to critical infrastructure. The ESCC includes utility CEOs and trade association leaders representing all segments of the industry. Its counterparts include senior Administration officials from the White House, relevant Cabinet agencies, federal law enforcement, and national security organizations.

The following table summarizes total year-over-year contractor and consulting costs by department.

Consultants & Contracts	2016 BUDGET	2017 BUDGET	2017 vs 2016 Budget
Compliance Assurance	200,000	50,000	(150,000)
Event Analysis	56,000	-	(56,000)
Compliance Investigation, Registration and Certification	50,000	-	(50,000)
Reliability Assessments and System Analysis	575,000	525,000	(50,000)
Performance Analysis	509,039	528,082	19,044
Situation Awareness	1,211,475	1,295,850	84,375
E-ISAC	748,335	899,835	151,500
CRISP	5,888,594	5,888,594	-
System Operator Certification	327,600	219,800	(107,800)
Continuing Education, Training & Education	348,200	360,800	12,600
General & Administrative	95,000	15,000	(80,000)
Information Technology	2,094,671	2,312,787	218,116
Human Resources	550,000	575,000	25,000
Finance and Accounting	297,000	457,000	160,000
TOTAL CONSULTANTS AND CONTRACTS	**12,950,914**	**13,127,749**	**176,835**

The Compliance Assurance department will require ongoing, though significantly reduced, consulting support for implementation of compliance assurance reform initiatives. Contract and consulting expenses for the Reliability Assessment, Performance Analysis, and System Analysis are largely for software and services supporting reliability data management and analysis. Situation Awareness costs are primarily related to licenses and services supporting Situation Awareness for FERC, NERC, and the Regional Entities (SAFNR), and other reliability information and notification (e.g., alerts) systems.

E-ISAC consulting costs for 2017 include support for GridEx and analytical tools. Approximately $6M of the total E-ISAC contract and consulting costs are CRISP related and funded by CRISP participants.

Training, Education, and Operator Certification contract and consulting costs include the cost of operator certification, training, and continuing education programs, and training NERC personnel. It also includes supporting compliance and enforcement (risk-based CMEP) and other training initiatives.

Information Technology (IT) contract and consulting support is primarily for systems and software maintenance and support services, including costs for enhancements to and maintenance of enterprise applications. Costs associated with IT security programs and the ongoing implementation and support of a document management program are also included. Software development costs are primarily budgeted under fixed (capital) assets and are discussed further below.

Human Resources contract and consulting costs are primarily for employee training, various surveys, compensation studies, and consulting services to support improvements in human resource information systems.

Finance and Accounting costs are primarily for audit and consulting services to support the Enterprise Risk Management and Internal Control audit plan and Compliance and Certification Committee (CCC) audit plan, as well as consulting services to implement new financial reporting tools and review insurance strategy and solutions.

Fixed Asset (Capital) Budget and Capital Financing

NERC's 2017 capital budget is approximately $4.4M (excluding depreciation), which represents an increase of approximately $461k from 2016. The table below provides a summary of the major capital budget components.

NERC CAPITAL BUDGET	2016	2017
ERO Application Development	$ 1,500,000	$ 700,000
E-ISAC Portal Development		1,000,000
Document Management	465,000	335,000
Hardware (Storage, servers, laptops)	955,000	991,000
Other Equipment	535,000	885,000
Disaster Recovery	200,000	150,000
NERC Software licenses	256,000	311,000
Total Capital Budget	**$ 3,911,000**	**$ 4,372,000**

NERC has budgeted $2.2M (both operating and capital expenses) in 2017 for services related to the planning, design, and implementation of software applications supporting the development of enterprise tools for common NERC and Regional Entity operations. These ERO Enterprise related costs include $700k in capital expenditures and $1.5M in other IT operating costs. Senior management from both NERC and the Regional Entities refined and updated the ERO Enterprise's long-term IT architecture and data management plans and the specific applications that will be under development in 2017. The IT department section offers further detail regarding updates to the Enterprise IT Strategy; the current status of the development of Enterprise IT applications; and projects that will be under development in 2017. Information regarding the cost and benefits of each project are also provided. The proposed $2.2M budget for 2017 related to enterprise application development and support is less than the 2017 projection presented in NERC's *2016 Business Plan and Budget* due largely to the decision to delay the development of a replacement for the current compliance monitoring and enforcement tracking system to 2018. Further information regarding the ERO Enterprise application development plan and budget is contained in Section A – Information Technology department. NERC's 2017 capital budget also includes ongoing funding for IT security, disaster recovery, data storage, replacement of servers and laptops, and software license costs.

The 2017 budget projection assumes that approximately $1.5M of the total $4.4M capital budget will be financed through the capital financing program that was described and put in place as part of NERC's *2014 Business Plan and Budget*. Further information regarding capital financing may be found in Exhibit D.

Working Capital and Operating Reserves

Management is proposing an overall reserve budget of $7.8M for the combined four categories of operating reserves and the Assessment Stabilization Reserve under the company's Working Capital and Operating Reserve Policy. This represents a decrease of $1.1M (11.9%) from the total reserve amounts included in NERC's approved 2016 budget. While individual categories reflect increases and decreases resulting from operating needs and uses, the budget does not reflect additional working capital requirements in total. Pursuant to the company's Working Capital and Operating Reserve policy, funds reserved for future liabilities are now budgeted under a separate reserve category entitled Future Obligation Reserve. This reserve is primarily comprised of existing funds and is budgeted to be $2.6M for 2017. The second category of operating reserves is the System Operating Certification Reserve. The 2017 System Operator Certification Reserve is budgeted at $714k and comprised of existing funds. The third category of operating reserves is the CRISP Operating Reserve, which represents funds dedicated to support CRISP. Similar to 2016, these reserves are established pursuant to a CRISP budget agreed to and funded entirely by utilities participating in CRISP. These reserves have no impact on assessments and they are segregated from other reserves pursuant to the terms of the CRISP agreements. Currently, the CRISP reserves are projected to be $500k in the 2017 budget.

The fourth category of operating reserves is the Operating Contingency Reserve. This reserve includes funds for expenditures that were not anticipated at the time the company's budget was prepared or for which the timing was uncertain. NERC's current policy on Operating Contingency Reserves requires a reserve target of 3.5–7.0%, except as otherwise approved by the Board after review and recommendation by the NERC Finance and Audit Committee. This percentage is calculated against NERC's total budget for operating and capital expenditures, less those costs related to CRISP and System Operator Certification (both having separate reserve categories). For this draft of the 2017 budget, management is recommending an Operating Contingency Reserve of approximately $2.2M, or 3.7% of total operating and capital costs, excluding CRISP and System Operator costs, which is slightly less than the minimum recommended in the policy but within the discretion of the NERC Board of Trustees to approve, upon review and recommendation of NERC's Finance and Audit Committee.

In addition to the four categories of operating reserves and as previously discussed, the company's amended Working Capital and Operating Reserve Policy also provides for an Assessment Stabilization Reserve. To date, this reserve has been funded entirely by previously received penalties and is projected to have a balance of $2.7M as of January 1, 2017, pending approval by the NERC Board. For purposes of the company's *2017 Business Plan and Budget*, management proposes the release of $1.1M in Assessment Stabilization Reserve funds to offset assessments. The use of $1.1M to offset assessments in 2017 yields an average increase of 4.9% over the 2016 assessments. The balance of $1.7M will be used to reduce assessments in a future period, subject to review and approval of the applicable year business plan and budget. A further discussion of the use of this remaining Assessment Stabilization Reserve balance may be found below in the section entitled 2018-2019 Projections.

Department Budget and FTE Comparisons

The following tables set forth a 2016–2017 total budget comparison by department. The amounts shown below reflect all direct and indirect departmental costs, including fixed asset costs. Costs incurred for general and administrative and other overheads are considered indirect, and are allocated to the statutory departments based on the ratio of that department's budgeted FTEs to total budgeted FTEs.

2016–2017 Total Budget by Department

Total Budget	Budget 2016	Budget 2017	Change 2017 Budget v 2016 Budget	% Change
Reliability Standards	8,193,116	8,100,282	(92,834)	-1.1%
Compliance Analysis, Certificaton and Registration	4,632,871	3,646,289	(986,582)	-21.3%
Compliance Assurance	9,420,903	7,858,599	(1,562,305)	-16.6%
Compliance Enforcement	5,293,298	5,800,647	507,349	9.6%
Reliability Assessments and Performance Analysis	9,918,728	12,444,449	2,525,721	25.5%
Training, Education and Operator Certification	3,912,231	3,757,501	(154,731)	-4.0%
Reliability Risk Management				
Event Analysis	5,355,795	5,446,206	90,411	1.7%
Situation Awareness	3,692,197	4,032,862	340,664	9.2%
E-ISAC	16,767,525	18,515,341	1,747,816	10.4%
Total Budget	67,186,665	69,602,175	2,415,510	3.6%
Total Funding	67,502,155	70,151,660	2,649,505	3.9%
Change in Working Capital	315,490	549,485	233,995	0.3%

The decreases in Compliance Analysis, Certification and Registration, and Compliance Assurance departments costs are primarily due to the transfer of resources from these departments as part of the internal reorganization to better align resources to support strategic goals and risk priorities. The increase in the Reliability Assessment and Performance Analysis program area and Event Analysis department budget are due to the reallocation of resources to that department to further support increased reliability risk assessment and analysis resource priorities. The increase in the Situation Awareness department is primarily due to enhancement or modification of reliability-related situation awareness and monitoring tools. The increase in the E-ISAC department is primarily due to planned enhancements to the E-ISAC portal and 2017 GridEx.

The following table presents a year-over-year comparison of FTEs by department and reflects 2016 personnel additions, interdepartmental transfers, and attrition assumptions. An FTE represents the number of employees employed full time during the year, plus the number of employees employed part time (less than full schedule) or during a portion of the year converted to a full-time basis. Headcount represents the total number of personnel employed during the year, regardless of the length of their employment during that year. FTEs will be less than headcount, unless there are no part-time employees or employees who are employed less than a full year. The company's 2017 personnel budget is based upon existing headcount and associated compensation and benefit costs, as well as assumptions on the number and cost of new hires, all within an overall FTE budget. An average vacancy rate is applied to each position and its associated costs to arrive at an overall personnel cost budget. The vacancy rate represents an adjustment, which is applied in the calculation of budgeted personnel costs to account for attrition and variations in the budget assumptions on the timing of new hires.

2016–2017 Year-Over-Year Comparison of FTEs by Department

Total FTE's by Program Area	Budget 2016	Budget 2017	Change from 2016 Budget
STATUTORY			
Operational Programs			
Reliability Standards	17.98	17.16	(0.8)
Compliance Analysis, Certification and Registration	10.14	7.52	(2.6)
Compliance Assurance	19.36	15.51	(3.9)
Compliance Enforcement	12.22	13.16	0.9
Reliability Assessments and Performance Analysis	18.67	23.50	4.8
Training, Education and Operator Certification	7.38	7.05	(0.3)
Event Analysis	11.06	11.28	0.2
Situation Awareness	5.53	5.64	0.1
E-ISAC	18.90	19.74	0.8
Total FTEs Operational Programs	**121.24**	**120.56**	**(0.7)**
Administrative Programs			
General & Administrative	17.52	16.92	(0.6)
Legal and Regulatory	12.22	11.28	(0.9)
Information Technology	22.13	23.27	1.1
Human Resources	2.77	2.82	0.0
Finance and Accounting	16.60	15.04	(1.6)
Total FTEs Administrative Programs	**71.23**	**69.33**	**(1.9)**
Total FTEs	**192.47**	**189.88**	**(2.5)**

*Reflects 2017 additions and transfers between departments, anticipated timing of 2017 hires, and assumes 6% attrition in all programs

Total FTEs in the Administrative Programs is decreasing 2.7%, reflecting reallocation of resources among the various departments The increase in Information Technology FTEs is due to the reallocation of personnel to strengthen project management oversight over NERC and ERO Enterprise software application development and implementation.

The NERC 2017 organizational chart can be found in Appendix 1**.** The difference between the number of positions reflected in the 2017 organizational chart and total 2017 budgeted FTEs is due to assumptions regarding vacancy rates and timing of new hires.

The following pages include a statement of activities comparing the 2016 budget and the proposed 2017 budget, followed by a statement of activities comparing the 2016 budget and the proposed 2017 budget with and without CRISP.

Statement of Activities and Fixed Assets Expenditures 2016 and 2017 Budgets

STATUTORY

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	% Inc 2017 over 2016	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding								
ERO Funding								
NERC Assessments	$ 57,081,445	$ 57,081,445	$ (0)	$ 59,856,314	$ 2,774,868	**4.9%**	$ 59,652,362	$ 203,952
Penalty Sanctions	1,439,000	1,439,000	-	1,100,000	(339,000)		1,100,000	-
Total NERC Funding	**$ 58,520,445**	**$ 58,520,445**	**$ (0)**	**$ 60,956,314**	**$ 2,435,868**		**$ 60,752,362**	**$ 203,952**
Third-Party Funding (CRISP)	6,830,738	7,335,757	505,019	6,990,447	159,709		6,910,701	79,746
Testing Fees	1,867,972	1,867,972	-	1,921,900	53,928		1,921,900	-
Services & Software	50,000	50,000	-	50,000	-		50,000	-
Workshops	230,000	269,201	39,201	230,000	-		230,000	-
Interest	3,000	35,898	32,898	3,000	-		3,000	-
Miscellaneous	-	202	202	-	-		-	-
Total Funding (A)	**$ 67,502,155**	**$ 68,079,475**	**$ 577,320**	**$ 70,151,660**	**$ 2,649,505**	**3.9%**	**$ 69,867,962**	**$ 283,698**
Expenses								
Personnel Expenses								
Salaries	$ 28,842,336	$ 29,052,918	$ 210,581	$ 30,073,438	$ 1,231,102		$ 29,979,980	93,458
Payroll Taxes	1,871,367	1,830,724	(40,643)	$ 1,847,130	(24,237)		1,908,285	(61,154)
Benefits	3,579,280	3,390,190	(189,090)	$ 3,643,806	64,526		3,668,103	(24,297)
Retirement Costs	2,990,823	3,015,135	24,312	$ 3,076,956	86,134		3,127,490	(50,533)
Total Personnel Expenses	**$ 37,283,807**	**$ 37,288,967**	**$ 5,161**	**$ 38,641,331**	**$ 1,357,525**	**3.6%**	**$ 38,683,857**	**(42,526)**
Meeting Expenses								
Meetings	$ 1,096,500	$ 1,194,500	$ 98,000	$ 1,071,500	$ (25,000)		$ 1,071,500	-
Travel	2,203,786	2,190,184	(13,602)	2,203,786	(0)		2,203,786	-
Conference Calls	320,000	261,880	(58,120)	97,600	(222,400)		97,600	-
Total Meeting Expenses	**$ 3,620,286**	**$ 3,646,564**	**$ 26,278**	**$ 3,372,886**	**$ (247,400)**	**-6.8%**	**$ 3,372,886**	**-**
Operating Expenses								
Consultants & Contracts	$ 12,865,914	$ 13,972,958	$ 1,107,044	$ 13,127,749	$ 261,835		$ 13,285,749	(158,000)
Office Rent	3,054,287	3,224,287	170,000	3,117,009	62,722		3,117,009	-
Office Costs	3,795,572	3,740,288	(55,284)	4,359,340	563,768		4,280,607	78,733
Professional Services	2,509,300	2,414,300	(95,000)	2,468,135	(41,165)		2,468,135	-
Miscellaneous	36,500	37,500	1,000	37,000	500		37,000	-
Depreciation	2,641,943	2,558,606	(83,336)	1,691,457	(950,486)		1,691,457	-
Total Operating Expenses	**$ 24,903,515**	**$ 25,947,939**	**$ 1,044,424**	**$ 24,800,690**	**$ (102,825)**	**-0.4%**	**$ 24,879,956**	**$ (79,267)**
Total Direct Expenses	**$ 65,807,608**	**$ 66,883,471**	**$ 1,075,863**	**$ 66,814,907**	**$ 1,007,299**	**1.5%**	**$ 66,936,699**	**$ (121,792)**
Indirect Expenses	**$ -**	**$ 0**	**$ 0**	**$ 0**	**$ 0**		**$ -**	**$ 0**
Other Non-Operating Expenses	**$ 110,000**	**$ 100,668**	**$ (9,332)**	**$ 106,725**	**$ (3,275)**	**-3.0%**	**$ 122,100**	**$ (15,375)**
Total Expenses (B)	**$ 65,917,608**	**$ 66,984,139**	**$ 1,066,531**	**$ 66,921,632**	**$ 1,004,024**	**1.5%**	**$ 67,058,799**	**$ (137,167)**
Change in Assets	**$ 1,584,548**	**$ 1,095,336**	**$ (489,211)**	**$ 3,230,028**	**$ 1,645,481**		**$ 2,809,163**	**420,865**
Fixed Assets								
Depreciation	$ (2,641,943)	$ (2,558,606)	83,336	$ (1,691,457)	$ 950,486		$ (1,691,457)	$ -
Computer & Software CapEx	2,447,000	2,362,402	(84,598)	2,572,000	125,000	**10.5%**	1,672,000	900,000
Furniture & Fixtures CapEx	-	-	-	-	-		-	-
Equipment CapEx	1,464,000	1,545,797	81,797	1,800,000	336,000		1,800,000	-
Leasehold Improvements	-	-	-	-	-		-	-
Allocation of Fixed Assets	**$ (0)**	$ (0)	$ 0	$ 0	$ 0		**$ -**	**$ 0**
Inc(Dec) in Fixed Assets (C)	**1,269,057**	**1,349,593**	**80,535**	**2,680,543**	**1,411,486**		**1,780,543**	**900,000**
TOTAL BUDGET (=B + C)	**$ 67,186,665**	**$ 68,333,732**	**$ 1,147,067**	**$ 69,602,175**	**$ 2,415,510**	**3.6%**	**$ 68,839,343**	**$ 762,833**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)[1]	**$ 315,490**	**$ (254,257)**	**$ (569,747)**	**$ 549,485**	**$ (716,491)**		**$ 1,028,620**	**$ (479,135)**
FTEs	**192.5**	**188.6**	**(3.9)**	**189.88**	**(2.6)**	**-1.3%**	**193.11**	**(3.23)**

[1]The budgeted change in working capital reflects both a reduction in excess working capital and operating reserves and the assumptions related to capital financing. Refer to Table B-1 on page 81 for a complete analysis of the Working Capital and Operating Reserve balance.

Statement of Activities and Fixed Assets Expenditures 2016 and 2017 Budgets

STATUTORY

	2016 Budget	2016 CRISP Budget	2016 Budget w/out CRISP	2017 Budget	2017 CRISP Budget	2017 Budget w/out CRISP	Variance 2017 Budget v 2016 Budget Over(Under)	% Inc 2017 over 2016
Funding								
ERO Funding								
NERC Assessments	$ 57,081,445	$ 1,108,641	$ 55,972,805	$ 59,856,314	$ 1,275,681	$ 58,580,633	$ 2,607,828	**4.7%**
Penalty Sanctions	1,439,000	33,572	$ 1,405,428	1,100,000	26,243	1,073,757	(331,671)	
Total NERC Funding	**$ 58,520,445**	**$ 1,142,213**	**$ 57,378,232**	**$ 60,956,314**	**$ 1,301,923**	**$ 59,654,390**	**$ 2,276,158**	
Third-Party Funding (CRISP)	6,830,738	6,830,738	$ -	6,990,447	6,990,447	$ -	-	
Testing Fees	1,867,972	-	$ 1,867,972	1,921,900	-	$ 1,921,900	53,928	
Services & Software	50,000	-	$ 50,000	50,000	-	$ 50,000	-	
Workshops	230,000	-	$ 230,000	230,000	-	$ 230,000	-	
Interest	3,000	68	$ 2,932	3,000	70	$ 2,930	(2)	
Miscellaneous	-	-	$ -	-	-	$ -	-	
Total Funding (A)	**$ 67,502,155**	**$ 7,973,019**	**$ 59,529,136**	**$ 70,151,660**	**$ 8,292,440**	**$ 61,859,220**	**$ 2,330,084**	**3.9%**
Expenses								
Personnel Expenses								
Salaries	$ 28,842,336	$ 592,724	$ 28,249,612	$ 30,073,438	$ 603,432	$ 29,470,007	$ 1,220,394	
Payroll Taxes	1,871,367	32,899	$ 1,838,469	1,847,130	32,329	$ 1,814,801	(23,668)	
Benefits	3,579,280	50,247	$ 3,529,034	3,643,806	68,375	$ 3,575,431	46,398	
Retirement Costs	2,990,823	65,802	$ 2,925,021	3,076,956	64,236	$ 3,012,721	87,700	
Total Personnel Expenses	**$ 37,283,807**	**$ 741,671**	**$ 36,542,135**	**$ 38,641,331**	**$ 768,371**	**$ 37,872,960**	**$ 1,330,825**	**3.6%**
Meeting Expenses								
Meetings	$ 1,096,500	$ 30,000	$ 1,066,500	$ 1,071,500	$ 30,000	$ 1,041,500	$ (25,000)	
Travel	2,203,786	37,455	$ 2,166,331	2,203,786	37,455	$ 2,166,331	(0)	
Conference Calls	320,000	2,000	$ 318,000	97,600	2,237	$ 95,363	(222,637)	
Total Meeting Expenses	**$ 3,620,286**	**$ 69,455**	**$ 3,550,831**	**$ 3,372,886**	**$ 69,692**	**$ 3,303,194**	**$ (247,637)**	**-7.0%**
Operating Expenses								
Consultants & Contracts	$ 12,865,914	$ 5,888,594	$ 6,977,320	$ 13,127,749	$ 5,888,594	$ 7,239,155	$ 261,835	
Office Rent	3,054,287	-	$ 3,054,287	3,117,009	-	$ 3,117,009	62,722	
Office Costs	3,795,572	304,027	$ 3,491,545	4,359,340	305,683	$ 4,053,657	562,112	
Professional Services	2,509,300	175,000	$ 2,334,300	2,468,135	175,000	$ 2,293,135	(41,165)	
Miscellaneous	36,500	250	$ 36,250	37,000	250	$ 36,750	500	
Depreciation	2,641,943	-	$ 2,641,943	1,691,457	5,297	$ 1,686,159	(955,783)	
Total Operating Expenses	**$ 24,903,515**	**$ 6,367,871**	**$ 18,535,644**	**$ 24,800,690**	**$ 6,374,824**	**$ 18,425,865**	**$ (109,779)**	**-0.6%**
Total Direct Expenses	**$ 65,807,608**	**$ 7,178,997**	**$ 58,628,611**	**$ 66,814,907**	**$ 7,212,888**	**$ 59,602,019**	**$ 973,409**	**1.7%**
Indirect Expenses	**$ -**	**$ 650,361**	**$ (650,361)**	**$ 0**	**$ 687,169**	**$ (687,169)**	**$ (36,809)**	
Other Non-Operating Expenses	**$ 110,000**	**$ -**	**$ 110,000**	**$ 106,725**	**$ -**	**$ 106,725**	**$ (3,275)**	**-3.0%**
Total Expenses (B)	**$ 65,917,608**	**$ 7,829,358**	**$ 58,088,250**	**$ 66,921,632**	**$ 7,900,057**	**$ 59,021,575**	**$ 933,325**	**1.6%**
Change in Assets	**$ 1,584,548**	**$ 143,662**	**$ 1,440,886**	**$ 3,230,028**	**$ 392,383**	**$ 2,837,645**	**$ 1,396,759**	
Fixed Assets								
Depreciation	$ (2,641,943)	$ -	$ (2,641,943)	$ (1,691,457)	$ (5,297)	$ (1,686,159)	$ 955,783	
Computer & Software CapEx	2,447,000	100,000	2,347,000	2,572,000	350,000	2,222,000	(125,000)	
Furniture & Fixtures CapEx	-	-	-	-	-	-	-	
Equipment CapEx	1,464,000	-	1,464,000	1,800,000	-	1,800,000	336,000	
Leasehold Improvements	-	-	-	-	-	-	-	
Allocation of Fixed Assets	**$ (0)**	$ 43,105	$ (43,105)	$ 0	$ 47,681	$ (47,681)	$ (4,575)	
Inc(Dec) in Fixed Assets (C)	**1,269,057**	**143,105**	**1,125,952**	**2,680,543**	**392,383**	**2,288,160**	**1,162,208**	**103.2%**
TOTAL BUDGET (=B + C)	**$ 67,186,665**	**$ 7,972,463**	**$ 59,214,202**	**$ 69,602,175**	**$ 8,292,440**	**$ 61,309,735**	**$ 2,095,533**	**3.5%**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)[1]	**$ 315,490**	**$ 556**	**$ 314,934**	**$ 549,485**	**$ -**	**$ 549,485**	**$ 234,551**	
FTEs	**192.47**	**2.8**	**189.71**	**189.88**	**2.8**	**187.06**	**(2.6)**	**-1.4%**

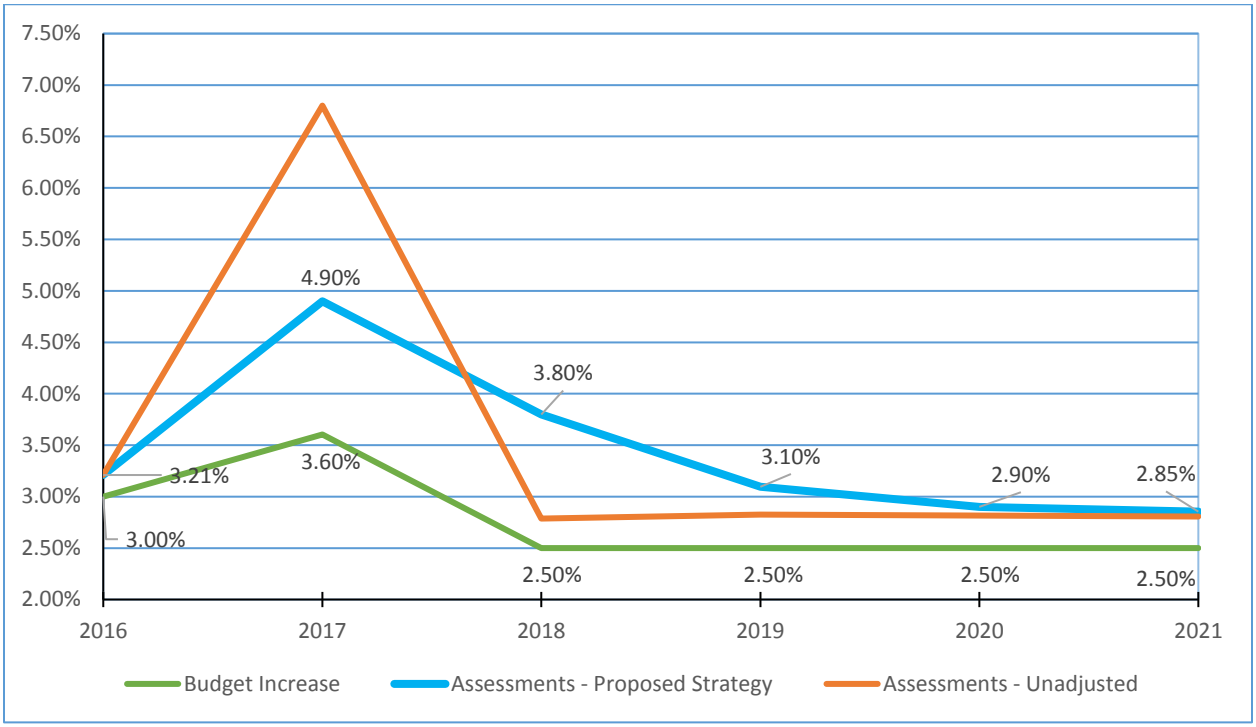
Projections for 2018–2019

Management has developed preliminary operating and fixed asset (capital) projections for 2018 and 2019. The significant assumptions considered in preparing these projections include:

- No increases in total FTEs over the 2017 budget
- Personnel and benefit cost increases are consistent with the 2017 budget assumptions
- Operating costs, including contractor and consulting expenses, are slightly higher due to increases in contract costs for rent, maintenance costs associated with software applications supporting ERO Enterprise Operations, and ongoing implementation of improved budgeting and financial reporting tools.
- Debt service repayment obligations in connection with the company's Capital Financing Program consistent with the projected Enterprise IT Applications capital forecast
- No increase in CRISP-related expenditures, except for personnel and benefit cost increases as noted above

Assessments are projected to increase by gradually declining percentages during the next three years as NERC implements a stabilization strategy. The goal of this strategy is to align budgeted costs and assessment increases more closely so that the unanticipated receipt of penalties will not cause large variances in future assessment projections. Currently, NERC projects assessments to increase 4.5% in 2017, 3.8% in 2018, and 3.1% in 2019 with declining releases each year from the Assessment Stabilization Reserve to meet these targets. A summary of these projections and reserve releases are shown in the table below. A budget increase of 2.5% was used for modeling purposes and is subject to change. The assessment strategy is also depicted in the graph below, showing the assumed budget increases, unadjusted assessment increases, and implementation of the assessment strategy.

	Budget	Assessment	----- Assessment Stabilization Reserve -----		
Year	Increase	Increase	Additions	Uses	Balance
2016	3.00%	3.21%	$ 3,710,000	$ (1,439,000)	$ 2,271,000
2017	3.60%	4.90%	1,000,000	(1,100,000)	2,171,000
2018	2.50%	3.80%	-	(410,000)	1,761,000
2019	2.50%	3.10%	-	(270,000)	1,491,000



The model does not assume any penalties beyond those we currently expect in 2016 and 2017 and includes $500k in penalty funds which NERC is scheduled receive in 2017 under the terms of an existing settlement agreement will be contributed to the Assessment Stabilization Reserve. While both the unexpected receipt of additional penalties and the current balance could yield a sizable amount of funds, future unexpected budget increases, ERO system development projects, or other one-time costs may be appropriate uses of these funds in order to stabilize assessments in the future.[16]

[16] In determining the amount of the Assessment Stabilization Reserve that is released each year, the company's Working Capital and Operating Reserve Policy requires that the NERC Finance and Audit Committee and Board review a three-year forecast of assessments, as well as the availability of funding for this reserve from surplus funds and penalty funds. The actual contributions and releases from the Assessment Stabilization Reserve in any year must be approved as part of NERC's annual business plan and budget process, with opportunity for review and input by stakeholders.

Statement of Activities and Fixed Assets Expenditures
2017 Budget & Projected 2018 and 2019 Budgets

	2017 Budget	2018 Projection	$ Change 18 v 17	% Change 18 v 17	2019 Projection	$ Change 19 v 18	% Change 19 v 18
Funding							
ERO Funding							
NERC Assessments	$ 59,856,314	$ 62,143,946	$ 2,287,633	3.8%	$ 64,088,553	$ 1,944,607	3.1%
Penalty Sanctions	1,100,000	410,000	(690,000)	-62.7%	-	(410,000)	-100.0%
Total NERC Funding	**$ 60,956,314**	**$ 62,553,946**	**$ 1,597,633**	**2.6%**	**$ 64,088,553**	**$ 1,534,607**	**2.5%**
Third-Party Funding (CRISP)	6,990,447	6,990,447	-	0.00%	6,990,447	-	0.0%
Testing Fees	1,921,900	1,921,900	-	0.00%	1,921,900	-	0.0%
Services & Software	50,000	50,000	-	0.00%	50,000	-	0.0%
Workshops	230,000	230,000	-	0.00%	230,000	-	0.0%
Interest	3,000	3,000	-	0.00%	3,000	-	0.0%
Miscellaneous	-		-			-	
Total Funding (A)	**$ 70,151,660**	**$ 71,749,293**	**$ 1,597,633**	**2.3%**	**$ 73,283,900**	**$ 1,534,607**	**2.1%**
Expenses							
Personnel Expenses							
Salaries	$ 30,073,438	$ 31,035,788	$ 962,350	3.2%	$ 31,966,862	$ 931,074	3.0%
Payroll Taxes	1,847,130	1,869,296	22,166	1.2%	1,893,597	24,301	1.3%
Benefits	3,643,806	3,887,941	244,135	6.7%	4,152,321	264,380	6.8%
Retirement Costs	3,076,956	3,141,573	64,616	2.1%	3,264,094	122,521	3.9%
Total Personnel Expenses	**$ 38,641,331**	**$ 39,934,598**	**$ 1,293,267**	**3.3%**	**$ 41,276,874**	**$ 1,342,276**	**3.4%**
Meeting Expenses							
Meetings	$ 1,071,500	$ 1,081,500	$ 10,000	0.9%	$ 1,071,500	(10,000)	-0.9%
Travel	2,203,786	2,203,786	-	0.0%	2,203,786	-	0.0%
Conference Calls	97,600	97,600	-	0.0%	97,600	-	0.0%
Total Meeting Expenses	**$ 3,372,886**	**$ 3,382,886**	**$ 10,000**	**0.3%**	**$ 3,372,886**	**$ (10,000)**	**-0.3%**
Operating Expenses							
Consultants & Contracts	$ 13,127,749	13,595,592	467,844	3.6%	14,367,077	771,485	5.7%
Office Rent	3,117,009	3,099,048	(17,961)	-0.6%	3,104,557	5,509	0.2%
Office Costs	4,359,340	4,359,340	-	0.0%	4,359,340	-	0.0%
Professional Services	2,468,135	2,652,075	183,940	7.5%	2,661,992	9,917	0.4%
Miscellaneous	37,000	37,000	-	0.0%	37,000	-	0.0%
Depreciation	1,691,457	1,194,345	(497,112)	-29.4%	932,549	(261,796)	-21.9%
Total Operating Expenses	**$ 24,800,690**	**$ 24,937,400**	**$ 136,711**	**0.6%**	**$ 25,462,516**	**$ 525,116**	**2.1%**
Total Direct Expenses	**$ 66,814,907**	**$ 68,254,885**	**$ 1,439,978**	**2.2%**	**$ 70,112,277**	**$ 1,857,392**	**2.7%**
Indirect Expenses	**$ -**	**$ -**			**$ -**	**$ -**	
Other Non-Operating Expenses	**$ 106,725**	**$ 114,000**	**$ 7,275**	**6.8%**	**116,000**	**2,000**	**1.8%**
Total Expenses (B)	**$ 66,921,632**	**$ 68,368,885**	**$ 1,447,253**	**2.2%**	**$ 70,228,277**	**1,859,392**	**2.7%**
Change in Assets	**$ 3,230,028**	**$ 3,380,408**	**$ 150,380**	**4.7%**	**$ 3,055,623**	**$ (324,785)**	**-9.6%**
Fixed Assets					-		
Depreciation	$ (1,691,457)	$ (1,194,345)	$ 497,112	-29.4%	$ (932,549)	$ 261,796	-21.9%
Computer & Software CapEx	2,572,000	2,562,000	(10,000)	-0.4%	2,112,000	(450,000)	-17.6%
Furniture & Fixtures CapEx	-	-	-		-	-	
Equipment CapEx	1,800,000	1,585,000	(215,000)	-11.9%	1,705,000	120,000	7.6%
Leasehold Improvements	-	-	-		-	-	
Allocation of Fixed Assets							
Inc(Dec) in Fixed Assets (C)	**$ 2,680,543**	**$ 2,952,655**	**$ 272,112**	**10.2%**	**$ 2,884,451**	**$ (68,204)**	**-2.3%**
TOTAL BUDGET (=B + C)	**$ 69,602,175**	**$ 71,321,540**	**$ 1,719,364**	**2.5%**	**$ 73,112,727**	**$ 1,791,188**	**2.5%**
FTEs	**189.88**	**189.88**	**-**		**189.88**	**-**	

Section A — 2015 Business Plan and Budget Program Area and Department Detail

Reliability Standards

Reliability Standards Program (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	17.98	17.16	(0.82)	17.66	(0.51)
Direct Expenses	$ 3,888,768	$ 3,861,666	$ (27,102)	$ 3,817,110	$ 44,556
Indirect Expenses	4,234,020	4,180,279	(53,741)	4,244,336	(64,056)
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	70,328	58,337	(11,991)	78,490	(20,153)
TOTAL BUDGET	$ 8,193,116	$ 8,100,282	$ (92,835)	$ 8,139,935	$ (39,653)

Background and Scope

The reliability standards program carries out the ERO's statutory responsibility to develop, adopt, obtain approval of, and modify (as and when appropriate) mandatory reliability standards (both continent-wide standards and regional reliability standards) for the reliable planning, operation, and critical infrastructure protection of the North American BES. The major activities undertaken by the Standards department include:

- **Delivering high-quality, continent-wide reliability standards**: NERC standard developers and other standards staff provide project management and leadership to develop solutions necessary to address reliability risks identified through the Reliability Risk Management Process (RRMP). These may include the development of, or modifications to, NERC reliability standards through standard development outreach activities, facilitation of drafting team activities, drafting support, assisting drafting teams in maintaining adherence to the development process as outlined in the *Standard Processes Manual*, and ensuring that the quality of documents produced is appropriate for approval by industry and the Board.
- **Facilitating continent-wide industry engagement**: NERC manages the work of over 200 industry contributors who serve on the Standards Committee, subgroups, and other project teams for the development of NERC reliability standards through the standards development program.
- **Conducting balloting, disseminating information, and supporting regulatory filings**: Through NERC's commenting and ANSI-accredited balloting process, industry consensus is built by engaging thousands of industry volunteers within hundreds of registered entities throughout North America who review, comment on, and approve the standards created by the standard drafting teams. The department also supports the filing of standards with regulatory authorities and provides support with regulatory proceedings.

The reliability standards program provides a mechanism for the eight Regional Entities to process regional standards when unique regional reliability gaps are detected, or incorporate Regional variances into continent-wide standards. The NERC Standards department staff supports regional standards development processes by providing technical advice, final quality review of regional standards, presentation to the Board, and preparation of regional standards materials for submission for standard adoption to the applicable regulatory authorities in the United States and Canada.

Stakeholder Engagement and Cost Effectiveness Project

As part of the standard development process, industry technical experts scope, draft, and review the new or revised NERC reliability standards for approval by the industry ballot body, adoption by the Board, and filing with regulatory authorities in the United States and Canada. Additionally, Federal, State and Provincial regulatory authorities, the NERC Board of Trustees, Regional Entities, and many industry stakeholders have expressed interest in the identification of costs incurred from implementing NERC reliability standards compared to risks they address. The desire is to ensure that these elements are considered during the standards development and revision process. A pilot was conducted in 2016 to develop an approach to determine the level of cost versus the reliability benefit to mitigate an identified risk. Work will continue in 2017 on refining the approach.

Key Efforts Underway

NERC will ensure that the Reliability Standards Development Plan is effectively executed and that reliability standards are focused on and mitigate significant risks to BES reliability. Department resources will be focused on supporting the strategic plan, including but not limited to support of the RRMP and resolving FERC directives. The Standards department will:

1. **Focus on the selection of projects undertaken.** Resources will be expended on issues determined to be a reliability risk through the RRMP (also see Reliability Assessment and System Analysis, and Performance Analysis section for additional detail). The department will apply broader project management skills to implement a variety of solutions to a reliability concern. An effective solution to an identified reliability risk may be a Reliability Standard, or it may be a guideline, information request, training, NERC Alert, technical conference, research, or a combination of these or other tools.
2. **Address FERC directives and respond to FERC orders** through standards development projects, as necessary. Each project will determine whether: (1) the directive will be complied with as issued, (2) there is an equally effective and efficient way to address the concern that fostered the directive, or (3) if there is technical justification (including that the directive has been overcome by events, processes, or advances in technology) that the directive is no longer needed.
3. **Perform Enhanced Periodic Reviews.** In 2016, as the reliability standards reach steady state, industry, NERC, and FERC will determine whether there is a need to make further improvements to the standards through enhanced periodic reviews, that include: (1) a measured review of the content of standards, considering whether the requirements could more effectively mitigate risks to the BPS; (2) whether the standards are results based and drafted with high quality; (3) whether the standards are concise or if the number of requirements could be reduced; and (4) whether compliance expectations are clear.
4. **Facilitate smooth transition to new standards**. This includes working with the Compliance Monitoring and Enforcement, Registration, and Reliability Assessment and System Analysis, and Performance Analysis programs to develop guidelines, webinars, and other activities to support auditor and industry training for the new standards.

The 2017–2019 RSDP will be developed in 2016 in conjunction with the Standards Committee, RISC, and RRMP. It will outline the work plan for the continued evaluation of NERC reliability standards, the Standards department's support of Reliability Risk Management, and resolution of FERC directives. Additionally, associated metrics will be developed and deployed to measure the overall quality of the reliability standard as a basis for measuring needed improvements.

2017 Goals and Deliverables

The transformation of the reliability standards to steady state is nearing completion.[17] Specifically, the majority of FERC directives will be addressed, as well as the remaining recommendations for retiring requirements made by the Paragraph 81 project and the independent experts. The body of standards will be improved while considering quality and content criteria as well as results-based standards principles. The NERC Standards staff will continue to address any new directives issued by FERC as well any reliability risks identified through RRMP or by the RISC for which a Reliability Standard is part of the solution.

Resource Requirements

Personnel

As in prior years, industry engagement is vital to the successful development of standards. The continued transformation of NERC standards to steady state will require additional industry engagement throughout 2016. In 2017, industry subject matter expert engagement requirements will be ongoing as enhanced periodic reviews are performed.

The NERC standards department continues to focus resources on the production of quality standards, rather than solely on the monitoring and execution of the standards process. Workload in the standards area during 2017 is anticipated to remain stable, with no additional personnel resources planned for 2017. The departmental travel expenses are expected to be the same as the 2016 levels, given the anticipated amount of outreach for the number of standards reviews expected to be in process, coupled with cost savings resulting from holding more meetings at NERC's Atlanta and Washington, DC, offices. The FTE reduction set forth in the table at the end of this section is the result of the allocation of standards staff towards more critical activities like cyber security and analytical capabilities

Contractors and Consultants

No contractor and consulting support is budgeted in 2017, which is consistent with the 2016 budget.

[17] As defined in the 2015-2017 RSDP, "steady state" means a stable set of clear, concise, high-quality and technically sound reliability standards that are results based, including retirement of requirements that do little to promote reliability.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
RELIABILITY STANDARDS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 7,869,295	$ 7,869,295	$ (0)	$ 7,835,213	$ (34,082)	$ 7,871,776	$ (36,563)
Penalty Sanctions	218,376	218,376		159,642	(58,734)	162,725	(3,082)
Total NERC Funding	**$ 8,087,671**	**$ 8,087,671**	**$ (0)**	**$ 7,994,855**	**$ (92,816)**	**$ 8,034,500**	**$ (39,645)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	105,000	105,000	-	105,000	-	105,000	-
Interest	445	5,374	4,929	427	(18)	435	(8)
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 8,193,116**	**$ 8,198,045**	**$ 4,929**	**$ 8,100,282**	**$ (92,834)**	**$ 8,139,935**	**$ (39,653)**
Expenses							
Personnel Expenses							
Salaries	$ 2,260,735	$ 2,349,773	$ 89,039	$ 2,340,405	$ 79,671	$ 2,300,735	39,670
Payroll Taxes	163,064	168,710	5,646	151,658	(11,406)	161,947	(10,289)
Benefits	327,239	289,808	(37,432)	307,085	(20,154)	291,462	15,623
Retirement Costs	250,560	265,961	15,401	259,407	8,847	259,856	(448)
Total Personnel Expenses	**$ 3,001,598**	**$ 3,074,252**	**$ 72,654**	**$ 3,058,556**	**$ 56,958**	**$ 3,014,000**	**44,556**
Meeting Expenses							
Meetings	$ 207,000	$ 207,000	$ -	$ 207,000	$ -	$ 207,000	-
Travel	271,988	230,000	(41,988)	271,988	-	271,988	-
Conference Calls	133,000	100,000	(33,000)	40,565	(92,435)	40,565	-
Total Meeting Expenses	**$ 611,988**	**$ 537,000**	**$ (74,988)**	**$ 519,553**	**$ (92,435)**	**$ 519,553**	**-**
Operating Expenses							
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -	$ -	-
Office Rent	-	-	-	-	-	-	-
Office Costs	64,622	42,784	(21,838)	51,336	(13,286)	51,336	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	210,060	231,843	21,783	231,721	21,661	231,721	-
Total Operating Expenses	**$ 275,182**	**$ 275,127**	**$ (55)**	**$ 283,556**	**$ 8,375**	**$ 283,556**	**$ -**
Total Direct Expenses	**$ 3,888,768**	**$ 3,886,379**	**$ (2,389)**	**$ 3,861,666**	**$ (27,102)**	**$ 3,817,110**	**$ 44,556**
Indirect Expenses	**$ 4,234,020**	**$ 4,458,581**	**$ 224,561**	**$ 4,180,279**	**$ (53,741)**	**$ 4,244,336**	**$ (64,056)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 8,122,788**	**$ 8,344,959**	**$ 222,171**	**$ 8,041,945**	**$ (80,843)**	**$ 8,061,445**	**$ (19,500)**
Change in Assets	**$ 70,328**	**$ (146,914)**	**$ (217,242)**	**$ 58,337**	**$ (11,991)**	**$ 78,490**	**(20,153)**
Fixed Assets							
Depreciation	$ (210,060)	$ (231,843)	$ (21,783)	$ (231,721)	$ (21,661)	$ (231,721)	$ -
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	**$ 280,388**	231,639	(48,749)	290,058	9,670	310,211	(20,153)
Inc(Dec) in Fixed Assets (C)	**70,328**	**(204)**	**(70,532)**	**58,337**	**(11,991)**	**78,490**	**(20,153)**
TOTAL BUDGET (=B + C)	**$ 8,193,116**	**$ 8,344,755**	**$ 151,639**	**$ 8,100,282**	**$ (92,834)**	**$ 8,139,935**	**$ (39,653)**
FTEs	**17.98**	**18.27**	**0.29**	**17.16**	**(0.82)**	**17.66**	**-0.51**

Compliance Monitoring and Enforcement and Organization Registration and Certification

The Compliance Monitoring, Enforcement, and Organization Registration and Certification Program Area's purpose is to monitor, enforce, and ensure registered entity compliance with the ERO's mandatory reliability standards. This program area is addressed by three operational groups: Compliance Assurance (addressing compliance monitoring), Reliability Assurance (addressing Assurance, Organization Registration and Certification), and Compliance Enforcement.

Compliance Assurance

Compliance Assurance addresses the Regional Entities' implementation of the compliance monitoring section of the Compliance Monitoring and Enforcement Program (CMEP). The group works in tandem with Compliance Enforcement, Standards, and Reliability Risk Management.

Compliance Assurance

Compliance Assurance (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	19.36	15.51	(3.85)	15.07	0.44
Direct Expenses	$ 4,559,233	$ 3,816,924	$ (742,308)	$ 3,615,394	$ 201,530
Indirect Expenses	4,559,714	3,779,431	(780,283)	3,621,833	157,598
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	301,956	262,244	(39,712)	264,713	(2,469)
TOTAL BUDGET	$ 9,420,903	$ 7,858,599	$ (1,562,304)	$ 7,501,940	$ 356,659

Background and Scope

NERC's Compliance Assurance group works collaboratively with the eight Regional Entities to ensure effective implementation of risk-based compliance monitoring under the CMEP across the entire ERO Enterprise. This program ensures that Regional Entities monitor registered entities for compliance according to their own specific facts and circumstances, including the entity's inherent risks, evaluation of controls in place to mitigate the inherent risks, as well as any aggravating factors. The CMEP provides for Regional Entities to develop customized compliance oversight plans (COPs) for each registered entity that identifies: 1) the standards or requirements to be monitored; 2) the monitoring processes (tools) for use by the Regional Entities, including compliance audits, self-certification, spot checking, investigations, self-reporting, periodic data submittals, and complaints; and 3) the frequency of monitoring. NERC and the Regional Entities ensure that inherent risk assessments (IRAs) for registered entities begin with a consistent framework and that Regional Entities' implementation of the CMEP coalesce around best practices, data management procedures that address data reporting requirements, integrity, retention, security, and confidentiality.

The Compliance Assurance group's responsibilities include but are not limited to the following major activities and functions:

- Oversight of the quality implementation of the risk-based compliance monitoring program;
- Development of the annual Implementation Plan (IP);
- Oversight of the use of necessary compliance-related processes, procedures, IT platforms, tools, and templates;

- Development and delivery of education and training for ERO Enterprise staff;
- Critical Infrastructure Protection (CIP) Version 5 activities related to education programs that support industry compliance and the integration of risk assessment and internal controls;
- CIP-014-1 training and outreach activities related to effective implementation of the Physical Security Reliability Standard;
- Coordination with the NERC Standards department for standard development to assist in the smooth transition for standards from development to enforceability;
- Support for Regional Entity and industry committees, working groups, and task forces, such as the NERC Compliance and Certification Committee; and
- Industry training for every Reliability Standard approved by FERC.

Stakeholder Engagement and Benefit

NERC continues to promote the Regional Entities' development of customized COPs for registered entities. As the risk-based compliance monitoring approach was implemented in 2015 and 2016, Regional Entities worked closely with stakeholders to develop IRAs and appropriately scope compliance monitoring activities. As this process matures in 2017, Regional Entities will continue to develop customized uses of compliance monitoring tools and frequency of monitoring for each registered entity, based on its IRA. Additionally, NERC continues to promote registered entities' development of effective compliance programs and internal controls, which may provide a benefit in the development of their COPs.

Compliance Assurance continues to work closely with the standard development program to provide compliance information, statistics, and perspectives to drafting teams fostering the development of standards that provide an increased reliability benefit and clarify compliance risks. This collaboration with industry and Standards department staff will occur early in the standard development process by providing draft compliance monitoring guidance, including information on how compliance with draft standards will be determined, as well as input to the drafting teams on the auditability and enforceability of the draft standards. This will ensure that ERO Enterprise tools used in the auditing process, such as the reliability standards auditing worksheet (RSAW), do not expand or modify standards requirements.

NERC also continues to provide industry-focused outreach events and webinars on the ERO Enterprise's approaches to risk-based CMEP activities. The ERO Enterprise staff will continue its webinar series providing guidance on standards and requirements associated with the 2017 risk elements identified for consideration for compliance monitoring.

Key Efforts Underway

Regional Entity Oversight for Risk-Based Compliance Monitoring

Consistent with the goals and objectives set forth in the strategic plan, NERC will continue to implement risk-based compliance monitoring and enforcement as part of its stated objectives of ensuring BES reliability, improving the efficiency and effectiveness of NERC and Regional Entity compliance and enforcement operations, focusing on identified risks and reducing unnecessary burdens on registered entities.

CIP Compliance and Transition

NERC and the Regional Entities continue to manage the smooth implementation of compliance activities for Version 5 and subsequent enhancements to the CIP Standards by providing training, webinars, and other forms of outreach. The ERO Enterprise will continue to provide educational programs to support

industry compliance and the integration of risk assessment and internal controls. In addition, NERC and the Regional Entities will continue supporting the successful implementation and monitoring of the physical security reliability standard.

2017 Goals and Deliverables

The Compliance Assurance group has several goals and deliverables that support the 2016-2019 *ERO Enterprise Strategic Plan.* Resources will be focused on building upon the framework and improvements implemented as a result of the risk-based compliance monitoring activities in 2016. Specific 2017 objectives for this group are:

- Continue to mature the risk-based compliance monitoring program, fully developing customized COPs for registered entities.
- Work closely with NERC's Enforcement and IT departments, as well as staff in the Regional Entities, on improvements to the existing compliance, reporting, analysis tracking system (C-RATS), and other compliance tools to support risk-based activities.
- Support the continued successful implementation of the CIP Version 5 reliability standards and subsequent enhancements that become effective in 2017 and beyond.
- Continue to monitor and support effective implementation and monitoring of the Physical Security Reliability Standard.
- Initiate a training program to support implementation of the common audit procedures for each Reliability Standard, integrating principles from the ERO Auditor Capabilities and Competencies Guide.
- Continue to integrate the standards and compliance functions for clear stakeholder implementation. Support this effort through common set of RSAWs, measures, or successors, for all standards. Initiate a compliance phase-in learning periods for new standards.

These 2017 activities are necessary to further implement risk-based compliance monitoring, including the CIP standards, and integrate the standards and compliance functions. A number of activities that support the implementation of the strategic risk-based reforms are intended to reduce regulatory burden by focusing monitoring according to each registered entity's potential impact on the BPS.

Resource Requirements

Personnel

The 2017 FTE reduction set forth in the table at the end of this section reflects the reallocation of 2016 budgeted FTEs to support key initiatives related to successful implementation and oversight of the risk-based CMEP.

Contractors and Consultants

Funds budgeted for outside consultants to assist in successful implementation of risk-based compliance monitoring have been reduced to $50k. While at a significantly reduced level from the 2016 budget, some resources are necessary to support the transformation of NERC's Compliance Monitoring and Enforcement Program to a risk-based design. In addition, the Information Technology budget includes funding for the maintenance of existing software tools supporting compliance assessment, registration, certification, and enforcement activities, as well as the investigation and development of a business case for future tools supporting ERO Enterprise ERO Enterprise compliance assessment, registration, and certification and enforcement activities.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
COMPLIANCE ASSURANCE

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 9,185,250	$ 9,185,250	$ (0)	$ 7,713,879	$ (1,471,371)	$ 7,362,710	$ 351,169
Penalty Sanctions	$ 235,174	$ 235,174		144,334	(90,840)	138,858	5,476
Total NERC Funding	**$ 9,420,424**	**$ 9,420,424**	**$ (0)**	**$ 7,858,213**	**$ (1,562,212)**	**$ 7,501,569**	**$ 356,644**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	479	4,710	4,231	386	(93)	371	15
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 9,420,903**	**$ 9,425,134**	**$ 4,231**	**$ 7,858,599**	**$ (1,562,305)**	**$ 7,501,940**	**$ 356,659**
Expenses							
Personnel Expenses							
Salaries	$ 3,063,004	$ 2,367,713	$ (695,290)	$ 2,509,618	$ (553,386)	$ 2,342,419	167,199
Payroll Taxes	205,979	159,939	(46,040)	163,335	(42,644)	158,287	5,048
Benefits	351,727	308,546	(43,180)	333,557	(18,170)	315,645	17,912
Retirement Costs	336,902	267,268	(69,634)	276,273	(60,629)	264,902	11,371
Total Personnel Expenses	**$ 3,957,612**	**$ 3,103,467**	**$ (854,145)**	**$ 3,282,783**	**$ (674,828)**	**$ 3,081,253**	**201,530**
Meeting Expenses							
Meetings	$ 60,000	$ 120,000	$ 60,000	$ 60,000	$ -	$ 60,000	-
Travel	276,343	322,000	45,657	276,343	-	276,343	-
Conference Calls	20,000	20,000	-	6,100	(13,900)	6,100	-
Total Meeting Expenses	**$ 356,343**	**$ 462,000**	**$ 105,657**	**$ 342,443**	**$ (13,900)**	**$ 342,443**	**-**
Operating Expenses							
Consultants & Contracts	$ 200,000	$ 115,000	$ (85,000)	$ 50,000	$ (150,000)	$ 50,000	-
Office Rent	-	-	-	-	-	-	-
Office Costs	44,779	38,880	(5,899)	141,198	96,419	141,198	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	-	-	-	-	-	-	-
Total Operating Expenses	**$ 245,279**	**$ 154,380**	**$ (90,899)**	**$ 191,698**	**$ (53,581)**	**$ 191,698**	**$ -**
Total Direct Expenses	**$ 4,559,233**	**$ 3,719,847**	**$ (839,386)**	**$ 3,816,924**	**$ (742,309)**	**$ 3,615,394**	**$ 201,530**
Indirect Expenses	**$ 4,559,714**	**$ 3,687,419**	**$ (872,294)**	**$ 3,779,431**	**$ (780,283)**	**$ 3,621,833**	**$ 157,598**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 9,118,947**	**$ 7,407,267**	**$ (1,711,681)**	**$ 7,596,355**	**$ (1,522,592)**	**$ 7,237,227**	**$ 359,128**
Change in Assets	**$ 301,956**	**$ 2,017,868**	**$ 1,715,912**	**$ 262,244**	**$ (39,712)**	**$ 264,713**	**(2,469)**
Fixed Assets							
Depreciation	-	-	-	-	-	-	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 301,956	$ 191,574	(110,382)	262,244	(39,712)	$ 264,713	(2,469)
Inc(Dec) in Fixed Assets (C)	**$ 301,956**	**$ 191,574**	**$ (110,382)**	**$ 262,244**	**$ (39,712)**	**$ 264,713**	**$ (2,469)**
TOTAL BUDGET (=B + C)	**$ 9,420,903**	**$ 7,598,841**	**$ (1,822,062)**	**$ 7,858,599**	**$ (1,562,305)**	**$ 7,501,940**	**$ 356,659**
FTEs	**19.36**	**15.11**	**(4.25)**	**15.51**	**(3.85)**	**15.07**	**0.44**

Compliance Analysis, Certification and Registration

Compliance Analysis, Certification and Registration (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	10.14	7.52	(2.62)	9.42	(1.90)
Direct Expenses	$ 2,086,784	$ 1,686,689	$ (400,093)	$ 1,913,981	$ (227,291)
Indirect Expenses	2,387,951	1,832,451	(555,499)	2,263,646	(431,194)
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	158,136	127,149	(30,988)	165,446	(38,297)
TOTAL BUDGET	$ 4,632,871	$ 3,646,289	$ (986,581)	$ 4,343,072	$ (696,783)

Background and Scope

The Reliability Assurance (Assurance, Certification and Registration) group is responsible for a range of requirements and activities embodied in Section 500 (Organization Registration and Certification) and Appendices 5A and 5B of the NERC Rules of Procedure. The group provides technical resource support to standards development, compliance monitoring, and enforcement and ensures that (1) all entities impacting the BES are registered commensurate with risk; (2) all RCs, TOPs, and BAs are certified; (3) conducts industry reliability assurance activities; and (4) compliance gaps identified in reportable events are assessed and addressed if appropriate. Specific activities of the group include:

- **Registration** – Identifies and registers BES users, owners, and operators who are responsible for compliance with reliability standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and complying with all applicable reliability standards. Maintains the current registration for the entire ERO for entities as they take on and drop functional responsibilities.
- **Certification** – Evaluates and certifies the competency of reliability entities; i.e., those that perform certain key reliability functions, specifically the RC, BA, and TOP functions. Entities performing these three functions must be evaluated for having the necessary personnel, knowledge, facilities, programs, and other qualifications to carry out these important responsibilities, including demonstrating the ability to meet the requirements and sub-requirements of all of the reliability standards applicable to the reliability function(s). This also includes confirming through the certification review process that a reliability entity continues to have the qualifications mentioned above following planned material changes to that entity's operation.
- **Reliability Assurance** – Conducts reliability assurance activities, including:
    - **Reliability Assurance** – Conduct activities to reasonably assure the ERO that certain actions have been taken as reported in response to NERC Alerts or guidance to industry. An example of this is the Right-of-Way Clearances, which is one of the 2015 ERO Enterprise high-priority risk projects.
    - **Oversight** – NERC provides oversight of Regional Entity implementation of regional registration, compliance, certification, investigation, complaint programs, and processes.
    - **Investigations** – Staff conducts non-public, confidential investigations to identify Possible Violations of NERC reliability standards in response to complaints, BES disturbances, or other similar triggers. Staff participates on all Regional Entity-led investigations and observe as requested on FERC-led reliability investigations and inquiries.

- **Compliance evaluations** – Staff works closely with regional staff to confirm that qualified events and disturbances are evaluated against the relevant approved reliability standards and ensure formal compliance monitoring occurs if indicated. These analyses are also shared with FERC staff.
- **Complaints** – NERC addresses formal complaints that allege the violation of reliability standards through a confidential process.

Key Efforts Underway

In 2014 and 2015, the Reliability Assurance, Certification and Registration group developed the risk-based Registration (RBR) design and registration criteria. FERC approved the design in 2015 in two orders, March 15 and October 15, which included the deactivation of Interchange Authorities (IAs), Load Serving Entities (LSEs) and Distribution Providers below 75 MW (DPs), as well as the creation of a NERC-led panel (Panel). In 2016, the ERO Enterprise implemented the Panel to review entities for deregistration or applicability to a reduced number of standards. The Panel will continue to review registration for individual entities and evaluate trends to determine emerging classes of similarly situated entities in 2017. In 2016, a review and identification of potential improvements in both the Registration and Certification programs is being undertaken. Improvements identified, will be considered for implementation in 2017.

2017 Goals and Deliverables

The Reliability Assurance group has several goals and deliverables that support the 2016-2019 *ERO Enterprise Strategic Plan.* Resources will be focused on building upon the improvements identified in 2016. Specific 2017 objectives for this group are:

- Continue to mature the NERC-led panel.
- Implement registration program improvements identified in the 2016 project, and conduct any additional actions identified by the project. Conduct training as necessary.
- Implement certification program improvements identified in the 2016 project and conduct training as necessary.

Resource Requirements

Personnel

No additional personnel are budgeted for 2017. The FTE count in the table at the end of this section reflects the 2016 merger of the registration and reliability assurance groups.

Contractor Expenses

No contractor expenses are budgeted in 2017.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
COMPLIANCE ANALYSIS, CERTIFICATION and REGISTRATION

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)
Funding					
ERO Funding					
NERC Assessments	$ 4,509,458	$ 4,509,458	$ 0	$ 4,256,053	$ (253,404)
Penalty Sanctions	$ 123,162	$ 123,162		86,786	(36,376)
Total NERC Funding	**$ 4,632,620**	**$ 4,632,620**	**$ 0**	**$ 4,342,840**	**$ (289,780)**
Third-Party Funding	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	251	251	0	232	(19)
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 4,632,871**	**$ 4,632,871**	**$ 0**	**$ 4,343,072**	**$ (289,799)**
Expenses					
Personnel Expenses					
Salaries	$ 1,410,333	$ 1,276,351	$ (133,982)	$ 1,284,717	$ (125,615)
Payroll Taxes	97,779	89,383	(8,396)	89,953	(7,826)
Benefits	184,238	200,291	16,053	208,842	24,604
Retirement Costs	157,451	144,473	(12,977)	145,981	(11,470)
Total Personnel Expenses	**$ 1,849,801**	**$ 1,710,498**	**$ (139,302)**	**$ 1,729,494**	**$ (120,307)**
Meeting Expenses					
Meetings	$ 4,000	$ 3,000	$ (1,000)	$ 4,000	$ -
Travel	155,146	134,000	(21,146)	155,146	-
Conference Calls	2,000	2,000	-	610	(1,390)
Total Meeting Expenses	**$ 161,146**	**$ 139,000**	**$ (22,146)**	**$ 159,756**	**$ (1,390)**
Operating Expenses					
Consultants & Contracts	$ 50,000	$ 50,000	$ -	$ -	$ (50,000)
Office Rent	-	-	-	-	-
Office Costs	25,338	17,365	(7,972)	24,231	(1,106)
Professional Services	-	-	-	-	-
Miscellaneous	500	500	-	500	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 75,838**	**$ 67,865**	**$ (7,972)**	**$ 24,731**	**$ (51,106)**
Total Direct Expenses	**$ 2,086,784**	**$ 1,917,364**	**$ (169,420)**	**$ 1,913,981**	**$ (172,803)**
Indirect Expenses	**$ 2,387,951**	**$ 2,274,301**	**$ (113,650)**	**$ 2,263,646**	**$ (124,305)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 4,474,734**	**$ 4,191,664**	**$ (283,070)**	**$ 4,177,626**	**$ (297,108)**
Change in Assets	**$ 158,136**	**$ 441,207**	**$ 283,070**	**$ 165,446**	**$ 7,309**
Fixed Assets					
Depreciation	-	-	-	-	-
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	$ 158,136	$ 118,030	(40,107)	165,446	7,309
Inc(Dec) in Fixed Assets (C)	**$ 158,136**	**$ 118,030**	**$ (40,107)**	**$ 165,446**	**$ 7,309**
TOTAL BUDGET (=B + C)	**$ 4,632,871**	**$ 4,309,694**	**$ (323,177)**	**$ 4,343,072**	**$ (289,799)**
FTEs	**10.14**	**9.55**	**(0.59)**	**9.42**	**(0.72)**

Compliance Enforcement

Compliance Enforcement (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	12.22	13.16	0.94	12.25	0.91
Direct Expenses	$ 2,225,938	$ 2,371,347	$ 145,410	$ 2,376,067	$ (4,720)
Indirect Expenses	2,876,962	3,206,790	329,827	2,942,739	264,050
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	190,398	222,510	32,112	215,079	7,431
TOTAL BUDGET	$ 5,293,298	$ 5,800,647	$ 507,350	$ 5,533,886	$ 266,761

Background and Scope

The Compliance Enforcement department is responsible for overseeing enforcement processes, the application of penalties or sanctions, and activities to mitigate and prevent recurrence of noncompliance with reliability standards. The Compliance Enforcement department works collaboratively with the eight Regional Entities to ensure consistent and effective implementation of the risk-based Compliance Monitoring and Enforcement Program. Importantly, the department also focuses on ensuring that the ERO Enterprise dedicates resources to the matters that pose the greatest risk to reliability.

The NERC Compliance Enforcement department performs its responsibilities by:

- Monitoring Regional Entities' enforcement processes and providing oversight over their outcomes to ensure due process, to identify best practices and process efficiency opportunities, and to promote consistency among Regional Entities' business practices;
- Collecting and analyzing compliance enforcement data and trends to assist with the identification of emerging risks and to help inform the development of enforcement policies and processes;
- Filing notices of penalty and other submittals associated with noncompliance discovered through Regional Entity compliance monitoring and enforcement activities;
- Processing and filing notices of penalty and other submittals associated with violations discovered through NERC-led investigations and audits;
- Collaborating with other NERC departments, including Compliance Assurance, Standards, Event Analysis, and Regional Entity Coordination; and
- Delivering training of the ERO Enterprise staff and registered entities, as well as supporting other outreach efforts.

The ERO Enterprise's enforcement jurisdiction is drawn from the Energy Policy Act of 2005 (the Act), which added section 215 to the Federal Power Act (FPA). Section 215 made compliance with electric reliability standards mandatory and authorized the creation of an ERO and Regional Entities to establish and enforce reliability standards. Under section 215(e)(1) of the FPA, NERC or a Regional Entity may impose a penalty on a user, owner, or operator of the BPS for a violation of a Reliability Standard approved by FERC. As the ERO, NERC has set forth Sanction Guidelines outlined in its Rules of Procedure that govern the ERO Enterprise's penalties and non-monetary sanctions for Reliability Standard violations. This document provides information on the ERO Enterprise's enforcement philosophy, i.e., the ERO Enterprise's approach for assessing and resolving noncompliance while continuing to work to bring entities into compliance with applicable reliability standards.

ERO Enterprise Core Values and Guiding Principles

The ERO Enterprise's 2016-2019 Strategic Plan[18] promotes the ERO Enterprise's core values and guiding principles, which are based on accountability and independence, responsiveness, fairness and inclusiveness, adaption and innovation, excellence, efficiency, and integrity. These core values and guiding principles support the four pillars of the ERO Enterprise's efforts, namely, reliability, assurance, learning, and a risk-based approach.

Strategic Goals Related to Enforcement

Strategic goal 2 provides that the ERO Enterprise shall:

> [b]e a strong enforcement authority that is independent, without conflict of interest, objective and fair, and promote a culture of reliability excellence through risk-informed compliance monitoring and enforcement. The ERO Enterprise retains and refines its ability to use standards enforcement when warranted and imposes penalties and sanctions commensurate with risk. The ERO Enterprise retains and refines its ability to use reliability standards enforcement when warranted and imposes penalties and sanctions commensurate with risk.

The risk-based enforcement approach allows for the appropriate allocation of resources to the issues that pose a higher level of risk to the reliability of the BPS.

Guiding Enforcement Principles

The following principles serve as guidelines for the conduct and behavior of all involved in the ERO Enterprise enforcement program to ensure alignment with strategic goal 2 and the ERO Enterprise's core values.

Compliance Enforcement Authorities are independent, without conflict of interest, objective, and fair.

The ERO Enterprise strives to be a strong enforcement authority that is independent, without conflict of interest, objective, and fair. NERC and each of the Regional Entities has a code of conduct addressing the professional and ethical standards applicable to its personnel. Foremost among these standards is the requirement that no person work on a matter where that work may affect the person's financial interest. The ERO Enterprise also expects its personnel to conduct themselves professionally and respectfully when engaging with registered entities or other stakeholders. Personnel who do not meet these standards are subject to discipline, up to and including termination.

Enforcement program promotes culture of reliability excellence through a risk-based approach.

The ERO Enterprise's risk-based enforcement philosophy generally advocates reserving enforcement actions under section 5.0 of the Compliance Monitoring and Enforcement Program for those issues that pose a higher risk to the reliability of the BPS. The risk of a noncompliance is determined based on specific facts and circumstances, including any controls in place at the time of the noncompliance. The ERO Enterprise works with registered entities to ensure timely remediation of potential risks to the reliability of the BPS and prevent recurrence of noncompliance. The enforcement process allows parties to address risks collaboratively and promote increased compliance and reliability through improvement of programs and controls at the registered entities.

The ERO Enterprise applies a presumption of non-enforcement treatment of minimal risk noncompliance to entities with demonstrated internal controls who are permitted to self-log such minimal risk issues. Regarding other issues posing a minimal risk, NERC and the Regional Entities may exercise appropriate

[18] The ERO Enterprise's 2016-2019 Strategic Plan

judgment whether to initiate a formal enforcement action or resolve the issue outside of the formal enforcement processes. The availability of streamlined treatment of minimal risk noncompliance outside of the formal enforcement process encourages self-inspection by registered entities. When self-identified minimal risk noncompliance is more than likely not going to be subject to a financial penalty, registered entities are encouraged to establish more robust internal controls for the detection and correction of noncompliance. This approach allows the ERO Enterprise to oversee the activities of registered entities in a more efficient manner and to focus resources where they result in the greatest benefit to reliability. In this context, efficiency does not necessarily mean less time or effort. Rather, it is using the requisite time, knowledge, and skills required for each circumstance. In addition, this approach allows the ERO Enterprise to continue to provide clear signals to registered entities about identified areas of concern and risk prioritization, while maintaining existing visibility into potential noncompliance and emerging areas of risk. Outcomes for noncompliance are based on the risk of a specific noncompliance and may range from streamlined, non-enforcement processes, to significant monetary penalties.

Enforcement actions are used and penalties are imposed when warranted, commensurate with risk.
An element of a risk-based approach to enforcement is accountability of registered entities for their noncompliance. No matter the risk of the noncompliance, the registered entity still bears the responsibility of mitigating that noncompliance. Based on the risk, facts, and circumstances associated with that noncompliance, the Regional Entity decides on an appropriate disposition track, inside or outside of an enforcement action, as described above, and whether a penalty is appropriate for the noncompliance.

Penalties are generally warranted for serious risk violations (e.g., uncontrolled loss of load, CIP program failures) and for when repeated noncompliance constitutes an aggravating factor. In addition to the use of significant penalties to deter undesired behavior, the ERO Enterprise also incents desired behaviors.[19] Specifically, Regional Entities may offset penalties to encourage valued behavior. Factors that may mitigate penalty amounts include registered entity cooperation, accountability (including admission of violations), culture of compliance, and self-identification of noncompliance.

Regional Entities may also grant credit in enforcement determinations for certain actions undertaken by registered entities for improvements in addition to mitigating factors. For example, Regional Entities may consider significant investments in reliability made by registered entities, beyond those otherwise planned and required, as an offset for proposed penalties in enforcement determinations. Regional Entities do not award credits or offsets for actions or investments undertaken by a registered entity that are required to mitigate noncompliance.

NERC engages in regular oversight of Regional Entity enforcement activities to confirm that the Regional Entities have followed the CMEP. This oversight evaluates the consistency of disposition methods, including assessment of a penalty or sanction, with previous resolutions of similar noncompliance involving similar circumstances. The NERC Board of Trustees Compliance Committee (the Compliance Committee) considers the recommendations of NERC staff regarding approval of Full Notices of Penalty and monitors the handling of noncompliance through the streamlined disposition methods of Spreadsheet NOPs, FFTs, and Compliance Exceptions.

[19] The Sanction Guidelines, Appendix 4B to the NERC Rules of Procedure, in alignment with Section 215, establish a general rule that penalties and sanctions imposed for the violation of a Reliability Standard shall bear a reasonable relation to the seriousness of the violation while also reflecting consideration of the other factors specified in the Sanction Guidelines. The Sanction Guidelines are available on NERC's website.

Actions are timely and transparent.
The ERO Enterprise maintains an elevated level of transparency regarding enforcement matters. NERC's Rules of Procedure (including the CMEP and Sanction Guidelines) and program documents are available to the public.[20] NERC also posts information on enforcement actions on a monthly basis.[21] Moreover, information on the efficiency of the enforcement program is available to the public on a quarterly basis.[22]

Noncompliance information is used as an input to other processes.
When developing risk elements, NERC annually identifies and prioritizes risks to the reliability of the BPS, taking into account factors such as compliance findings, event analysis experiences, and data analysis. In addition, Regional Entities consider factors such as noncompliance information when conducting an IRA of a registered entity. The ERO Enterprise also uses noncompliance information as part of a feedback loop to the standards development process. This allows enhanced reliability standards through appropriate information flows from compliance monitoring and enforcement to the standards drafting process and other NERC programs. NERC regularly provides analysis and lessons learned from noncompliance information to the public.[23]

Stakeholder Engagement and Benefit

Over the past few years, NERC and the Regional Entities have made substantial progress in reducing the number of instances of noncompliance remaining to be evaluated and processed. The ERO Enterprise has held registered entities accountable for instances of noncompliance that posed a risk to the reliability of the BPS while ensuring that enforcement actions are timely and transparent. NERC promotes a culture of reliability excellence by examining registered entities' internal compliance programs and considering them as mitigating factors in penalty determinations.

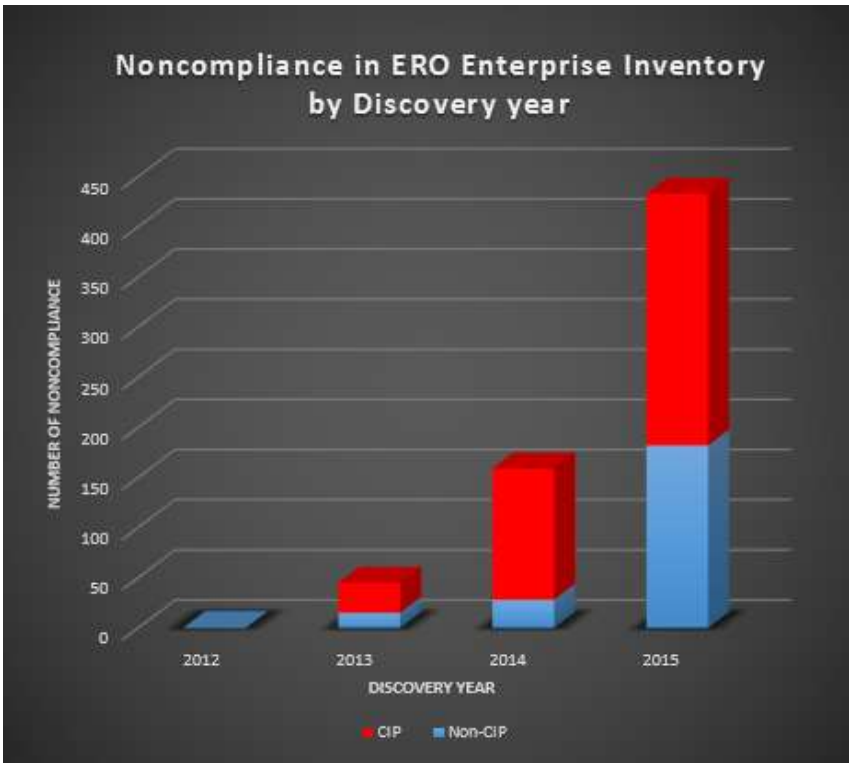
Processing Efficiencies

In an effort to improve the efficiency of enforcement processing throughout the ERO Enterprise, NERC developed a series of key enforcement processing metrics, which are tracked and analyzed throughout the year. In addition, since 2012, NERC has established goals to reduce the number of older violations remaining to be processed. Working with NERC, the Regional Entities invested significant time and resources in processing the older violations. As a result, the ERO Enterprise as a whole reduced the number of older violations substantially.

As of the end of 2015, there were three hundred twenty (320) violations older than 24 months. Sixty-four (64) of these violations stemmed from 9 non-federal registered entities and two hundred fifty-six (256) violations derived from 13 federal registered entities. The vast majority of the violations have either been fully mitigated or have mitigation plans in progress.

The targets and thresholds for processing efficiency-related metrics remain the same in 2016. This is because the ERO Enterprise is stable with regard to enforcement processing. This has only been possible due to the hard work of the Regional Entities and NERC Enforcement in eliminating backlog and incorporating new enforcement processes and procedures into practice.

[20] The NERC Rules of Procedure
[21] Posted compliance exceptions, Spreadsheet Notices of Penalty, and Full Notices of Penalty
[22] Quarterly enforcement program
[23] Quarterly compliance reports



Continued Outreach Efforts in 2016 and Beyond

In 2016, NERC and the Regional Entities will continue to conduct outreach activities that focus on self-logging, compliance exceptions, risk elements, CIP Version 5, Inherent Risk Assessments, and internal controls. NERC plans to use existing industry events, such as the Standards and Compliance workshops and industry webinars, to provide information on compliance monitoring and enforcement activities.

In addition, NERC and the Regional Entities will conduct industry outreach on reliability standards approved by FERC in 2016. These events will focus on the approved new standards or modifications to existing standards along with implementation timelines. Although most events will take place via webinar, some events will be delivered as workshops.

Risk-Based CMEP Implementation

On February 19, 2015, FERC approved the implementation of the risk-based CMEP. The goal of the risk-based CMEP is to shift the compliance and enforcement approach from one in which all instances of noncompliance are evaluated as Possible Violations to an approach that strengthens management practices and reserves the enforcement process for instances of noncompliance that have been found to pose a greater risk to reliability. The programs discussed below, in conjunction with compliance outreach encouraging the development of strong management practices, will advance NERC's progress toward this goal.

Compliance Exceptions

A compliance exception is an alternative disposition method and is not a dismissal, Find, Fix, Track (FFT), or Notice of Penalty. It is essentially the exercise of enforcement judgment with respect to a noncompliance regardless of its method of discovery (self-report, self-certification, compliance audit finding, etc.). The process of identifying and recording a compliance exception builds on the FFT program. The ERO Enterprise uses judgment in the process by taking into account the facts and circumstances of the noncompliance, the risk posed by the noncompliance to the reliability of the BPS, and the deterrent

effect of an enforcement action or penalty, among other things. Compliance exception treatment is available for issues that pose a minimal risk to the BPS that would be mitigated within 12 months of the date the compliance exception is posted.

In 2013 and 2014, the use of compliance exceptions (as the alternative disposition for noncompliance posing a minimal risk to the reliability of the BPS) was limited to allow the testing of the new process. In 2015, this disposition track became available throughout the ERO Enterprise. Use of compliance exceptions as a disposition track has increased steadily. Minimal risk issues continue to be the majority of the caseload. Regional Entities have continued to use the compliance exception disposition method and increasingly relied upon it for minimal-risk issues. The increase in compliance exception use has corresponded with a decline in the use of the FFT disposition track.



Self-Logging

NERC and Regional Entity enforcement staff also have worked closely with stakeholders to identify potential improvements to self-reporting and other enforcement processes. A number of improvements were designed and implemented in 2013 and 2014. The self-logging program allows registered entities that have demonstrated effective management practices to keep track of minimal-risk noncompliance (and related mitigation) on a log that is periodically reviewed by the Regional Entity.

In November 2015, FERC approved the ERO Enterprise Self-Logging Program document, which includes the method to evaluate eligibility.[24] The program is available to any registered entity that would like to be evaluated by its Regional Entity in accordance with the program requirements. Self-logging became available to all registered entities that met the program qualifications at the start of 2015, and 42 registered entities have been approved by Regional Entities to self-log as of December 31, 2015. NERC is conducting a review of the self-logging program, in coordination with FERC staff, during 2016.

NERC Oversight of Risk-Based CMEP Implementation

For 2016, ensuring the successful implementation of NERC's risk-based CMEP remains the priority of Compliance Enforcement's oversight plan. As part of that oversight and in addition to offering regular feedback to the Regional Entities, NERC will continue to identify areas for improvement or promoting

[24] *North American Electric Reliability Corporation*, 153 FERC ¶ 61,130 (2015). The self-logging program document is available on NERC's website.

consistency through training, guidance, or adjustment the following year. NERC also produces an ERO Enterprise CMEP annual report, which includes an assessment of the risk-based CMEP implementation. NERC expects to publish that report during Q1 2017.

NERC performs oversight of the Regional Entities' enforcement programs primarily through the review of the processes, supporting evidence, and other information provided by the Regional Entities over the course of focused engagements of program areas that are scheduled throughout the year. NERC communicates the recommendations and findings to the Regional Entities to help the ERO Enterprise develop responsive strategies and solutions to potential issues and ensure uniform and consistent implementation of the CMEP. Such recommendations and findings also help identify priority areas for training of ERO Enterprise staff during the year.

Other Key Enforcement Efforts Underway

Regional Entity Training

NERC Enforcement will provide training to Regional Entity staff on the most important elements of risk-based enforcement, including risk assessment of noncompliance and the determination of appropriate penalties and sanctions for noncompliance. NERC is developing this training based on observations from its oversight activities of Regional Entity settlement agreements, as well as the process reviews described above.

2017 Goals and Deliverables

Specific 2017 objectives for the Compliance Enforcement department include:

- Refining and improving the risk-based CMEP processes;
- Implementing in a transparent manner an ERO Enterprise enforcement philosophy that is risk focused and drives desired behaviors by registered entities;
- Expanding the feedback loop of information from Enforcement to Standards and other program areas; and
- Working closely with NERC's Compliance Assurance and Information Technology departments, as well as staff in the Regional Entities, regarding the evaluation of improvements in the existing compliance, reporting, analysis tracking system, and other compliance tools to support risk-based activities.

Resource Requirements

Personnel

No changes to current Enforcement staffing levels are proposed in 2017.

Contractor Expenses

The Information Technology budget includes funding for the maintenance, evaluation, and development of enterprise tools supporting technical feasibility exceptions, registration, and enforcement activities.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
COMPLIANCE ENFORCEMENT

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 5,144,612	$ 5,144,612	$ 0	$ 5,677,854	$ 533,242	$ 5,420,762	$ 257,092
Penalty Sanctions	148,384	$ 148,384		122,465	(25,919)	112,822	9,643
Total NERC Funding	**$ 5,292,996**	**$ 5,292,996**	**$ 0**	**$ 5,800,319**	**$ 507,323**	**$ 5,533,584**	**$ 266,735**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	302	3,682	3,380	327	25	302	26
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 5,293,298**	**$ 5,296,678**	**$ 3,380**	**$ 5,800,647**	**$ 507,349**	**$ 5,533,886**	**$ 266,761**
Expenses							
Personnel Expenses							
Salaries	$ 1,629,233	$ 1,755,799	$ 126,566	$ 1,790,859	$ 161,627	$ 1,791,830	(971)
Payroll Taxes	109,485	113,380	3,895	117,205	7,720	117,447	(241)
Benefits	222,877	176,404	(46,473)	184,106	(38,771)	185,432	(1,326)
Retirement Costs	181,419	196,458	15,039	198,694	17,275	200,877	(2,182)
Total Personnel Expenses	**$ 2,143,014**	**$ 2,242,042**	**$ 99,028**	**$ 2,290,865**	**$ 147,851**	**$ 2,295,585**	**(4,720)**
Meeting Expenses							
Meetings	$ 2,500	$ 2,500	$ -	$ 2,500	$ -	$ 2,500	-
Travel	56,736	55,000	(1,736)	56,736	-	56,736	-
Conference Calls	1,200	2,000	800	366	(834)	366	-
Total Meeting Expenses	**$ 60,436**	**$ 59,500**	**$ (936)**	**$ 59,602**	**$ (834)**	**$ 59,602**	**$ -**
Operating Expenses							
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -	$ -	-
Office Rent	-	-	-	-	-	-	-
Office Costs	21,866	14,983	(6,883)	20,379	(1,486)	20,379	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	1,000	500	500	-	500	-
Depreciation	122	122	-	-	(122)	-	-
Total Operating Expenses	**$ 22,488**	**$ 16,105**	**$ (6,383)**	**$ 20,879**	**$ (1,608)**	**$ 20,879**	**$ -**
Total Direct Expenses	**$ 2,225,938**	**$ 2,317,647**	**$ 91,708**	**$ 2,371,347**	**$ 145,409**	**$ 2,376,067**	**$ (4,720)**
Indirect Expenses	**$ 2,876,962**	**$ 2,989,470**	**$ 112,507**	**$ 3,206,790**	**$ 329,827**	**$ 2,942,739**	**$ 264,050**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 5,102,901**	**$ 5,307,116**	**$ 204,216**	**$ 5,578,137**	**$ 475,236**	**$ 5,318,807**	**$ 259,330**
Change in Assets	**$ 190,398**	**$ (10,438)**	**$ (200,836)**	**$ 222,510**	**$ 32,112**	**$ 215,079**	**7,431**
Fixed Assets							
Depreciation	(122)	(122)	-	-	122	-	-
Computer & Software CapEx	-	107,000	107,000	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 190,520	$ 155,313	(35,207)	222,510	31,990	$ 215,079	7,431
Inc(Dec) in Fixed Assets (C)	**$ 190,398**	**$ 262,191**	**$ 71,793**	**$ 222,510**	**$ 32,112**	**$ 215,079**	**$ 7,431**
TOTAL BUDGET (=B + C)	**$ 5,293,298**	**$ 5,569,308**	**$ 276,009**	**$ 5,800,647**	**$ 507,349**	**$ 5,533,886**	**$ 266,761**
FTEs	**12.22**	**12.25**	**0.03**	**13.16**	**0.94**	**12.25**	**0.91**

Reliability Assessment and System Analysis

Reliability Assessments and System Analysis (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	11.75	14.10	2.35	14.13	(0.03)
Direct Expenses	$ 3,778,595	$ 3,986,965	$ 208,370	$ 4,031,697	$ (44,731)
Indirect Expenses	2,768,236	3,435,846	667,610	3,395,468	40,378
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	(202,709)	112,782	315,491	122,547	(9,765)
TOTAL BUDGET	$ 6,344,123	$ 7,535,594	$ 1,191,470	$ 7,549,713	$ (14,119)

Background and Scope

The Reliability Assessment and System Analysis (RASA) department carries out the ERO's statutory responsibility to conduct assessments of the reliability and adequacy of the BES. These assessments are used to provide insight and guidance about reliability risks. These insights provide a foundation for the development of new reliability standards or modifications to mandatory reliability standards, or other initiatives, such as guidelines, alert(s), webinars, etc., all focused on enhancing overall reliability. The majority of the activities in the RASA department directly address the risk priorities established by the Reliability Issues Steering Committee. In particular, the risks pertaining to changing resources and planning noted in the 2015 RISC report are of particular importance to the assessment and analysis work being performed in RASA.

NERC staff works closely with stakeholders on creating assessment development schedules, including schedules with adequate stakeholder review at every level. All NERC reliability assessments have a sponsoring technical committee, subcommittee, or other subgroup. The Long-Term and Seasonal assessments are conducted by the Reliability Assessment Subcommittee, and ultimately endorsed by the Planning Committee. Special Assessments often require a separate and specialized task force or advisory group to help construct, conduct, and produce special topic assessments such as the CPP assessments, Natural Gas interdependency assessment, and distributed energy report.

The department focuses on developing a technical framework and understanding the emerging reliability risks facing the industry. It also provides guidance and insights to stakeholders across North America. The department relies on its own engineering and analysis expertise, as well as Regional Entity and stakeholder resources. RASA is responsible for:

- Independent reliability assessments on the overall reliability and adequacy of the BES and associated emerging reliability risks that could impact the short-, mid- and the long-term (e.g., 10-year) planning horizons, and other reliability issues requiring an in-depth analysis.
- Support for the development and improvement of long-term sustainable interconnection-based power flow, dynamic, and load models that exhibit the accuracy and fidelity reflecting actual BES reliability performance and dynamic conditions.
- Interconnection-wide analysis of steady-state and dynamic conditions, including frequency, Essential Reliability Services, stability, and oscillatory behavior aspects.

- Advancement of industry and the ERO's understanding of power system characteristics and behaviors by gathering larger PMU datasets of data for advanced data analytics and modeling improvements.

- Assurance oversight that the BES electrical elements necessary for its reliable operation are identified, requiring the elements to follow the appropriate NERC Reliability Standards.

- Establishment of reliability leadership and consistent, technically sound guidance and recommendations that position industry and policy makers to enhance reliability through effective outreach and communications.

Stakeholder Engagement and Benefit

RASA works with industry leaders to create a reliability strategy that is relevant, timely, and effective to address the most important reliability risks. This effort includes reviewing and addressing key priority risks identified by NERC's Reliability Issues Steering Committee's (RISC); synthesizing key information identified through analysis and assessment efforts; extracting and prioritizing the associated reliability risks; sharing and integrating risk analysis insights across the ERO Enterprise; and translating that knowledge into actionable guidance and recommendations for NERC management, the Board, and entities, along with state, federal, and provincial policy makers.

In addition, the ERO monitors the ongoing and historic reliability performance of the BES through data gathered to analyze historic trends. The ERO provides reports and recommendations regarding the anticipated conditions that could impact the reliability, security, and stability of the BPS to the industry, Regional Entities, regulatory entities, and other designated entities.

2017 Enhancements

Enhancements in the 2017 BP&B are a reflection of the strategic goals and objectives identified in the Electric Reliability Organization Enterprise Strategic Plan 2016–2019.[25] The following enhancements are attributable to strategic goal #4[26] and the objectives and valued outcomes noted within the goal #4a:

- Improve resource adequacy assessments with increased probabilistic and risk analysis
- Conduct interconnection-wide analysis to support NERC's reliability assessments and improve industry planning
- Increase technical analysis and assessment focus on natural gas, wind, and solar resource and fuel availability
- Develop technical references and guidelines that advance and improve reliability using new technologies
- Develop quality/fidelity assessments of interconnection models

Key RASA Efforts Underway

RASA focuses its efforts in the following key areas:

Reliability Assessment

Reliability assessments serve to evaluate the expected reliability of the BES through extensive deterministic and probabilistic analyses to identify potential reliability risks and potential mitigation approaches. These reviews include both evaluations at the edge of the planning horizon, as well as

[25] http://www.nerc.com/AboutNERC/Documents/ERO%20Enterprise%20Strategic%20Plan%202016%E2%80%932019.pdf

[26] ERO Enterprise identifies, evaluates, studies, and independently assesses emerging risks to reliability.

assessments of the anticipated performance during the short-term (12- to 18-month outlook). These analyses involved planned and anticipated changes to generation resources, transmission infrastructure, and load behavior compared to base-line needs of the system to remain reliable and formulate recommendations and related guidance. This assessment is often by completed by examining special scenarios and unique situations within the BES. These analyses provide a technical platform for important policy discussions on challenges facing the interconnected BES, as well as focused recommendations on mitigation to improve overall reliability or lessen reliability risks.

By identifying and quantifying emerging reliability issues, NERC is able to provide risk-informed recommendations and support a learning environment for industry to address emerging risks and pursue improved reliability performance. These efforts are expected to expand to assess the impacts on reliability from the changing resource mix, reliability behavior of resources, distributed energy resources, and loads. Many resource additions are asynchronous and energy-limited, requiring assessment of a substantial number of scenarios rather than just seasonal peak conditions. Reliability assessments must therefore include a greater focus on probabilistic approaches, assessing the sufficiency of essential reliability services as well as focusing seasonal assessments on short-term horizons to encompass more than peak condition reserve margin analyses.

Key assessments include:

- Long-Term Reliability Assessment (supplemented by the Probabilistic Assessment)
- Summer and Winter Reliability Assessments (condensed report)
- Short-Term and Special Reliability Assessments
    a. Between one and four short-term reliability assessments are expected, driven by the need to assess emerging short-term risks to reliability
    b. Special Assessments are selected based on high-priority/high-risk issues that require an independent assessment from the ERO.

A significant ongoing effort anticipated to involve RASA, Regional Entity staff, and stakeholders focuses on the continued development of effective Essential Reliability Services. These efforts are expected to lead to a broad set of recommendations that will culminate with defined elements, an evaluation of initial metrics and data compilation of actual performance, and refinement about the ongoing assessment of Essential Reliability Services measures.

System Analysis

Understanding the technical behavior of the North American grid is the foundation for identifying crucial aspects of performance that are important for sustaining overall reliability. NERC's understanding of grid behavior is achieved through a comprehensive evaluation of system behavior through constant observation and study, analytic simulations, and forensic analysis of system disturbances. Methodically comparing the simulation results of powerflow and system dynamic performance to actual system behavior improves models critical for industry use to simulate system conditions as well as enables RASA to gain insights to enhance predictive system analysis.

The ERO Enterprise RAPA team also supports the following objectives:

- Continue leading and improving NERC's analytical capabilities to address a broad range of engineering topics,
- Support NERC Reliability Standards development with subject matter expertise,
- Support and lead technical analysis of emerging risks requiring advanced analytics and interconnection-wide assessment,

- Detailed forensic analysis of significant system disturbances

Key focus areas:

- PMU Measurement, use, and analysis improvements
  - Synchrophasor technology
  - Power plant model verification
  - Oscillation analysis
- Frequency Response Analysis, Interconnection Frequency Response Obligation Analysis, and forward-looking reliability assessment
- Interconnection-Wide Model Building Designation and Criteria administration
- Analysis of TPL Footnote 12
- Load and distributed energy resource modeling
- Event analysis – simulation and forensic analysis of major events
- Reliability Standards support
- BES Exception and Self-Determined Notification Processing

Further, RASA will continue to work closely with other organizations, including but not limited to the Electric Power Research Institute (EPRI), the Department of Energy (DOE), the Institute of Electrical and Electronic Engineers (IEEE), the Institute of Nuclear Power Operations (INPO), the North American Transmission Forum (NATF), the North American Generation Forum (NAGF), and the Canadian Electricity Association (CEA). RASA collaborates with these groups on a number of fronts, including geomagnetic disturbance (GMD), vegetation management, and variable generation integration. RASA will continue working with the Interstate Natural Gas Association of America (INGAA) and the Natural Gas Supply Association (NGSA) regarding studies pertaining to the interdependency of gas and electric systems.

2017 Goals and Deliverables

In 2017, RASA will seek to achieve several specific goals and objectives as part of the strategic focus of the ERO Enterprise (Goal 4a):

1. Pioneer implementation of advanced reliability assessment and system analysis methods to address the changing nature of the grid. Issue reliability assessment reports, guidelines, and recommendations to address high priority evolving performance trends and address emerging risks to reliability.
   a. Expand the use of probabilistic assessment tools across the ERO and gain consistency in approach
   b. Special assessments on identified high-priority risks (from RISC prioritization and recommendations)[27]
      - Changing resource mix and maintaining Essential Reliability Services

27 http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Recommendations_to_the_Board.pdf

- Increased penetration of Distributed Energy Resources
- Increasing dependency on generation fueled by natural gas
- Broaden understanding of inter-area and local system oscillations in all interconnections and their potential impact on interconnection reliability.

c. As part of its oversight of the Regional Entities, build and sustain an Enterprise RAPA team (ERO-RAPA) that encompasses the consistent development and implementation of risk-informed approaches and structured methods to identify and address reliability risks.

2. Provide the basis for industry to meet regulatory requirements of the NERC Reliability Standard BAL-003-1, "Frequency Response and Frequency Bias Setting;" exploratory understanding of frequency response; support interconnection-wide studies of frequency response
   a. Frequency Response Annual Analysis and BAL-003 FERC filing
   b. Determination of Interconnection Frequency Response Obligation (IFRO) and BA FRO values
3. Support NERC Reliability Standard development by providing subject matter expertise.
4. Provide support and leadership to (1) the Planning Committee and (2) standing committees' subcommittees, working groups, and task forces serving the standing committees. Support the development of technical reference documents and Reliability Guidelines with support of the PC leadership and established in the annual PC work plan
5. As necessary, support major event investigations, analyses, and reporting of findings, recommendations, and lessons learned to improve reliability.
6. Provide feedback to interconnection-wide model-building groups on improvements to system model quality and fidelity.
7. Assist in the development of approaches to registration and provide input to NERC staff in support of the development CMEP risk elements, as well as support and lead the BES Definition Exception Process.

Resource Requirements

Personnel
Additional personnel were allocated to RASA in 2016 to address increased resource demands associated with ongoing reliability assessment, performance analysis, and system analysis activities.

Contractor Expenses
The total contractor and consultant expenses for the department are projected at $525k, a decrease of $50k from the 2016 budget. Further information is provided on Exhibit C.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
RELIABILITY ASSESSMENTS and SYSTEM ANALYSIS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 6,135,872	$ 6,135,872	0	$ 7,339,030	$ 1,203,158	$ 7,354,185	$ (15,154)
Penalty Sanctions	142,718	142,718		131,213	(11,505)	130,180	1,033
Total NERC Funding	**$ 6,278,590**	**$ 6,278,590**	**$ 0**	**$ 7,470,243**	**$ 1,191,653**	**$ 7,484,364**	**$ (14,121)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	50,000	-	(50,000)	50,000	-	50,000	-
Workshops	15,000	15,000	-	15,000	-	15,000	-
Interest	462	3,634	3,172	351	(111)	348	3
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 6,344,052**	**$ 6,297,224**	**$ (46,828)**	**$ 7,535,594**	**$ 1,191,542**	**$ 7,549,713**	**$ (14,119)**
Expenses							
Personnel Expenses							
Salaries	$ 1,826,951	$ 2,080,813	$ 253,862	$ 2,247,826	$ 420,875	$ 2,258,124	(10,298)
Payroll Taxes	122,096	137,089	14,993	142,919	20,823	148,547	(5,628)
Benefits	213,866	240,723	26,857	263,230	49,364	269,401	(6,171)
Retirement Costs	203,274	229,385	26,111	246,609	43,335	251,613	(5,003)
Total Personnel Expenses	**$ 2,366,187**	**$ 2,688,010**	**$ 321,823**	**$ 2,900,585**	**$ 534,398**	**$ 2,927,684**	**(27,100)**
Meeting Expenses							
Meetings	$ 109,000	$ 109,000	$ -	$ 74,000	$ (35,000)	$ 109,000	(35,000)
Travel	208,338	249,000	40,662	208,338	-	208,338	-
Conference Calls	17,280	17,280	-	5,270	(12,010)	5,270	-
Total Meeting Expenses	**$ 334,618**	**$ 375,280**	**$ 40,662**	**$ 287,608**	**$ (47,010)**	**$ 322,608**	**(35,000)**
Operating Expenses							
Consultants & Contracts	$ 575,000	$ 442,425	$ (132,575)	$ 525,000	$ (50,000)	$ 525,000	-
Office Rent	-	-	-	-	-	-	-
Office Costs	116,266	138,523	22,257	147,652	31,386	130,283	17,368
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	386,024	282,034	(103,991)	125,621	(260,403)	125,621	-
Total Operating Expenses	**$ 1,077,790**	**$ 863,482**	**$ (214,308)**	**$ 798,773**	**$ (279,018)**	**$ 781,404**	**$ 17,368**
Total Direct Expenses	**$ 3,778,595**	**$ 3,926,772**	**$ 148,177**	**$ 3,986,965**	**$ 208,370**	**$ 4,031,697**	**$ (44,731)**
Indirect Expenses	**$ 2,768,236**	**$ 3,218,866**	**$ 450,630**	**$ 3,435,846**	**$ 667,610**	**$ 3,395,468**	**$ 40,378**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 6,546,832**	**$ 7,145,638**	**$ 598,806**	**$ 7,422,812**	**$ 875,980**	**$ 7,427,165**	**$ (4,354)**
Change in Assets	**$ (202,780)**	**$ (848,413)**	**$ (645,634)**	**$ 112,782**	**$ 315,562**	**$ 122,547**	**(9,765)**
Fixed Assets							
Depreciation	(386,024)	(282,034)	103,991	(125,621)	260,403	(125,621)	-
Computer & Software CapEx	-	53,580	53,580	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 183,316	$ 167,231	$ (16,084)	238,403	$ 55,088	$ 248,168	(9,765)
Inc(Dec) in Fixed Assets (C)	**$ (202,709)**	**$ (61,222)**	**$ 141,486**	**$ 112,782**	**$ 315,491**	**$ 122,547**	**$ -**
TOTAL BUDGET (=B + C)	**$ 6,344,123**	**$ 7,084,415**	**$ 740,292**	**$ 7,535,594**	**$ 1,191,471**	**$ 7,549,713**	**$ (14,119)**
FTEs	**11.75**	**13.19**	**1.44**	**14.10**	**2.35**	**14.13**	**(0.03)**

Performance Analysis

Performance Analysis (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	6.92	9.40	2.49	9.42	(0.02)
Direct Expenses	$ 1,838,245	$ 2,459,356	$ 621,111	$ 2,460,815	$ (1,459)
Indirect Expenses	1,628,513	2,290,564	662,051	2,263,646	26,918
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	107,841	158,936	51,095	165,446	(6,510)
TOTAL BUDGET	$ 3,574,599	$ 4,908,855	$ 1,334,256	$ 4,889,906	$ 18,949

Background and Scope

The Performance Analysis (PA) group provides insight and guidance about reliability risks and areas of concern based on analysis of historic system performance. This includes identifying potential risks of concern related to system, equipment, entity, and organizational performance that may indicate a need to develop remediation strategies, action plans, or data used to create, revise or retire reliability standards or consider new reliability standards. The department focuses on developing a technical framework and understanding the reliability risks facing the industry.

Stakeholder Engagement and Benefit

The ERO monitors the reliability performance of the BES in North America through data gathered to analyze historic trends. The ERO provides reports and recommendations regarding the anticipated conditions that could impact the reliability, security, and stability of the BPS to the industry, Regional Entities, regulatory entities, and other designated entities.

The ERO works with industry leaders to create a reliability strategy that is relevant, timely, and effective at addressing the most important reliability risks. This effort includes PA's contribution (both in data gathering and in statistical analysis of data, trends, and events) toward the ERO's understanding key information identified through analysis and assessment efforts; extracting and prioritizing the associated reliability risks from that information; sharing and integrating those risk analysis insights across the ERO Enterprise; and translating that knowledge into actionable guidance and recommendations for NERC management, the Board, and entities, and state, federal, and provincial policy makers. This offers stakeholders an open and transparent approach for the development of NERC's reliability strategy, ultimately ensuring the ERO is accountable to industry, regulators, and the public at large.

Key Efforts Underway

Performance Analysis collects transmission outage, generator performance, demand response, and protection and control misoperation data in a common format using the various industry databases. This data is used to develop and report on grid metrics that analyze outage frequency, duration, causes, and many other factors related to transmission and generator performance as well as automatic power system protection and control effectiveness. In addition to collecting simple equipment availability, detailed information about individual outage events is collected that, when analyzed at the regional and NERC levels, provides data that may be used to improve BES reliability.

The key trends, findings, and recommendations from Performance Analysis serve as technical input to the ERO's reliability standards and standards project prioritization, compliance process improvements, event analyses, reliability assessment, and critical infrastructure protection efforts. This analysis of BES performance provides an industry reference for historical BES reliability, but it also offers analytical

insights that lead toward the prioritization of specific actionable risk control steps for industry. These analyses and results are summarized in the annual state of reliability report, which provides guidance and recommendations for enhanced bulk system reliability. By January, 2017, PA will add GADS Wind Data to the data collected under Section 1600, requiring the development of a new software tool to enable this.

Performance Analysis is working with Event Analysis to develop a link between their databases. Specific equipment outages will be linked to disturbance reports filed with NERC, enabling better association of transmission and generation outages. The continued alignment between these efforts is expected to enhance the ability to conduct effective event analyses as well as identify key reliability areas for trend analyses of multiple databases. This is expected to improve the depth of event analyses across the ERO Enterprise and expand the quality of data gathered for sophisticated statistical and probabilistic analyses. This will lead to trends and insights about reliability performance, as well as effective measures and actions to address reliability risks. Further in 2016, PA has begun data mining of completed EA efforts to see if any insight might be gained from these events as the grid evolves that were not front and foremost or particularly relevant to enhanced grid reliability at the time of the original event investigation.

Performance Analysis is currently refining the composition of NERC's annual state of reliability (SOR) report to expand the GADS data trend analysis, and for 2017 begin to reflect post-seasonal reliability review, insights from analysis of transmission, generator, and demand response data systems (TADS, GADS, and DADS), and integration of event analysis and misoperations. Also, in 2016, the department will perform activities necessary to determine whether in 2017 the SOR should move from a calendar year (Q1-Q4) report to a fiscal year (2016,Q4-2017,Q3) report.

Further, Performance Analysis will continue to work closely with other organizations, including but not limited to the Electric Power Research Institute (EPRI), the Department of Energy (DOE), the Institute of Electrical and Electronic Engineers (IEEE), the Institute of Nuclear Power Operations (INPO), the North American Transmission Forum (NATF), the North American Generation Forum (NAGF), and the Canadian Electricity Association (CEA). PA collaborates with these groups on a number of fronts, including TADS, GADS, and DADS.

2017 Goals and Deliverables

In 2017, Performance Analysis has a number of specific goals and deliverables in support of the Strategic Plan, including:

1. Issue the state of reliability report, guidelines, recommendations, alerts as needed (including the verification and validation of data and information through Regional Entities and technical committees as required)
2. Oversee and evaluate reliability trends that identify reliability risks by analyzing data contained in NERC's the Generating, Transmission, and Demand Response Availability Data Systems (GADS, TADS, and DADS), along with reliability metrics and protection & controls system misoperations.
3. Support NERC Reliability Standard development by providing subject matter expertise.
4. Provide support and leadership to the standing committees' subcommittees, working groups, and task forces serving the standing committees (primary focus on the Performance Analysis Subcommittee and its subgroups.
5. Assist in the development of approaches to registration and provide input to NERC staff in support of the development of CMEP risk elements
6. Conduct major event investigations, analyses, and reporting of major findings, recommendations, and lessons learned that will improve reliability.

7. Provide insight on emerging system protection issues, and hand-off any issues gleaned with future implications to RASA.

Resource Requirements

Personnel

During 2016 additional personnel (including open positions) were allocated to Performance Analysis to address increased resource demands associated with ongoing reliability assessment, performance analysis, and system analysis activities.

Contractor Expenses

Performance Analysis contractor and consultant expenses are $528k, an increase of $19k over 2016. Additional details are provided in Exhibit C.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
PERFORMANCE ANALYSIS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 3,490,625	$ 3,490,625	$ -	$ 4,821,146	$ 1,330,521	$ 4,802,887	$ 18,259
Penalty Sanctions	84,052	84,051		87,475	3,423	86,786	689
Total NERC Funding	**$ 3,574,677**	**$ 3,574,676**	**$ -**	**$ 4,908,621**	**$ 1,333,944**	**$ 4,889,674**	**$ 18,948**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	50,000	50,000	-	-	-	-
Workshops		-	-	-	-	-	-
Interest		2,554	2,554	234	234	232	2
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 3,574,677**	**$ 3,627,230**	**$ 52,554**	**$ 4,908,855**	**$ 1,334,178**	**$ 4,889,906**	**$ 18,949**
Expenses							
Personnel Expenses							
Salaries	$ 886,643	$ 1,280,436	$ 393,793	$ 1,349,579	$ 462,936	$ 1,341,820	7,760
Payroll Taxes	65,373	90,958	25,585	92,093	26,720	95,140	(3,048)
Benefits	126,252	142,204	15,952	143,104	16,852	154,659	(11,556)
Retirement Costs	98,314	144,446	46,132	149,018	50,704	151,902	(2,885)
Total Personnel Expenses	**$ 1,176,582**	**$ 1,658,044**	**$ 481,462**	**$ 1,733,794**	**$ 557,212**	**$ 1,743,522**	**(9,728)**
Meeting Expenses							
Meetings	$ 1,000	$ 6,000	$ 5,000	$ 1,000	$ -	$ 1,000	-
Travel	118,172	98,000	(20,172)	118,172	-	118,172	-
Conference Calls	9,720	7,000	(2,720)	2,965	(6,755)	2,965	-
Total Meeting Expenses	**$ 128,892**	**$ 111,000**	**$ (17,892)**	**$ 122,137**	**$ (6,755)**	**$ 122,137**	**-**
Operating Expenses							
Consultants & Contracts	$ 509,039	$ 621,849	$ 112,810	$ 528,082	$ 19,043	$ 546,082	(18,000)
Office Rent	-	-	-	-	-	-	-
Office Costs	23,732	51,194	27,462	74,843	51,111	48,574	26,269
Professional Services	-	-	-	-	-	-	-
Miscellaneous		-	-	500	500	500	-
Depreciation		-	-	-	-	-	-
Total Operating Expenses	**$ 532,771**	**$ 673,043**	**$ 140,272**	**$ 603,426**	**$ 70,655**	**$ 595,156**	**$ 8,269**
Total Direct Expenses	**$ 1,838,245**	**$ 2,442,087**	**$ 603,842**	**$ 2,459,356**	**$ 621,111**	**$ 2,460,815**	**$ (1,459)**
Indirect Expenses	**$ 1,628,513**	**$ 2,242,712**	**$ 614,200**	**$ 2,290,564**	**$ 662,051**	**$ 2,263,646**	**$ 26,918**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 3,466,758**	**$ 4,684,799**	**$ 1,218,041**	**$ 4,749,920**	**$ 1,283,162**	**$ 4,724,460**	**$ 25,459**
Change in Assets	**$ 107,919**	**$ (1,057,569)**	**$ (1,165,487)**	**$ 158,936**	**$ 51,016**	**$ 165,446**	**(6,510)**
Fixed Assets							
Depreciation		-	-	-	-	-	-
Computer & Software CapEx	-	162,500	162,500	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 107,841	$ 116,517	$ 8,676	158,936	$ 51,095	$ 165,446	(6,510)
Inc(Dec) in Fixed Assets (C)	**$ 107,841**	**$ 279,017**	**$ 171,176**	**$ 158,936**	**$ 51,095**	**$ 165,446**	**$ -**
TOTAL BUDGET (=B + C)	**$ 3,574,599**	**$ 4,963,816**	**$ 1,389,217**	**$ 4,908,855**	**$ 1,334,257**	**$ 4,889,906**	**$ 18,949**
FTEs	**6.92**	**9.19**	**2.28**	**9.40**	**2.49**	**9.42**	**(0.02)**

Reliability Risk Management

NERC's Reliability Risk Management (RRM) group carries out the ERO's statutory responsibility to perform assessments (real time or near real time continual awareness, detailed analysis of significant events, and longer-tern broad performance assessments) of the reliability and adequacy of the BES, including identifying potential issues of concern relating to system, equipment, entity, and human performance that may indicate the need to develop and implement targeted interventions. RRM has three departments: Situation Awareness (also referred to as Bulk Power System Awareness), Event Analysis, and Performance Analysis, as described above beginning on page 53. These departments are responsible for six primary functions: (1) BES awareness; (2) event analysis and determination of root and contributing causes; (3) assessment of human performance challenges that affect BES reliability and identification of improvement opportunities; (4) continent-wide analysis and reporting of BES performance; (5) support of the NERC Operating Committee; and (6) support of the NERC Critical Infrastructure Protection Committee.

RRM's functions and resources are directly focused on proactive awareness of BES conditions and all events over a threshold of certain risk or impact. Through awareness and continuous assessment, RRM identifies potential reliability risks to the BES. RRM analyzes events in detail, addresses the most significant risks to BES reliability, and ensures that industry is well informed of system events, emerging trends, risk analysis, and lessons learned. Through performing these functions, RRM provides data and analysis to inform the other aspects of NERC's statutory functions. The group also provides strategic direction for using risk-based concepts in planning and executing its responsibilities.

Situation Awareness

Situation Awareness (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	5.53	5.64	0.11	5.65	(0.01)
Direct Expenses	$ 2,310,875	$ 2,570,828	$ 259,953	$ 2,509,043	$ 61,785
Indirect Expenses	1,302,775	1,374,338	71,563	1,358,187	16,151
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	78,547	87,695	9,148	91,601	(3,906)
TOTAL BUDGET	$ 3,692,197	$ 4,032,862	$ 340,664	$ 3,958,831	$ 74,030

Background and Scope

NERC's Situation Awareness department and the eight Regional Entities monitor BES conditions, significant occurrences and emerging risks, and threats across the 14 Reliability Coordinator regions in North America to maintain an understanding of conditions and situations that could impact the bulk electric system's reliable operation. This group also supports the development and publication of Alerts and awareness products and facilitates information sharing among industry, Regions, and the government during crisis situations and major system disturbances. The process for understanding the potential threats or vulnerabilities to the reliability of the BPS starts with understanding occurrences and events in the context in which they occur.

Stakeholder Engagement and Benefit

BES conditions continually change and provide recognizable signatures through automated tools, mandatory reports and voluntary information sharing, and third-party publicly available sources. The significant majority of these signatures represents conditions and occurrences that have little or no

reliability impact, either positive or adverse, on the BES. However, being cognizant of the short-term condition of the BES and the signatures associated with the entire range of reliability performance helps the ERO identify significant occurrences and events more accurately and efficiently. Registered entities continue to robustly share information and collaborate with the ERO in an effort to maintain and improve the overall reliability of the grid.

Key Efforts Underway

Several reliability-related situation awareness and monitoring tools will undergo enhancement, replacement, streamlining, or modification. The following tools are being focused on during 2016: (1) operation and maintenance of Situation Awareness for NERC, FERC, and Regions, Version 2 (SAFNRv2) software application used for monitoring, to include preparation for a new RFP process in late 2016 to enhance the tool from its current state with no changes to the data used; (2) operation and maintenance of the current secure NERC Alerts tool while planning for a streamlined NERC Alert process and platform appropriately integrated with related ongoing NERC, E-ISAC and ERO Enterprise IT initiatives; (3) refresh of the Reliability Coordinator Information System (RCIS) legacy application for operability and maintainability reasons, with no significant changes to functionality; and (4) continuing to set the conditions to bring limited streaming Synchrophasor data into NERC for wide-area situational awareness and event triage applications.

2017 Goals and Deliverables

In 2017, the Situation Awareness department will seek to accomplish the following specific goals and deliverables:

1. Ensure that the ERO is aware of all BES events above a threshold of impact.
2. Enable the sharing of information and data to facilitate wide-area situational awareness.
3. During crisis situations, facilitate the exchange of information among industry, Regions, and the U.S. and Canadian governments.
4. Keep industry informed of emerging reliability threats and risks to the BES, including any expected actions.
5. Conduct the annual NERC Monitoring and Situational Awareness Conference and Human Performance Conference.
6. Administer the NERC Alerts process as specified in ROP §810 to issue Advisory (Level 1) Alerts on significant and emerging reliability- and security-related topics as needed, and facilitate the tracking of actions specified in Recommendation (Level 2) and Essential Action (Level 3) Alerts.

The department uses the following major reliability-related tools to support department activities:

Resource Adequacy (ACE Frequency) Tool

This software application provides continuous monitoring of key resource adequacy performance metrics, including pre-established thresholds and limits defined in standards. It alerts Reliability Coordinators and resource subcommittees to conditions that could result in critical inadequacies, such as major tie errors, inaccurate load forecasts, and inadequate frequency response.

Inadvertent Interchange

This tool facilitates the entering of monthly scheduling data and submittal of monthly inadvertent performance standards reports to NERC. It also assists in the monitoring and resolution of reliability issues originated by inadvertent interchange imbalances.

Frequency Monitoring and Analysis Tool

This tool detects frequency events and captures key frequency response information for each interconnection.

Intelligent Alarms Tool

This tool detects short-term and long-term frequency deviations using data transmitted to NERC by the Balancing Authorities. When coupled with the FNet[28] and Frequency Monitoring and Analysis tools, this tool allows immediate differentiation of the cause of a frequency deviation—a generator trip or a scheduling error.

Genscape

The PowerIQ and PowerRT tools provide more detailed insight into current-day conditions impacting BPS conditions in both normal operations and stressed conditions.

Resource Requirements

Personnel

No additional personnel are projected for the Situation Awareness department in 2017. The slight increase reflected in the following table is due to a lower vacancy rate than in 2016.

Contractor Expenses

The overall funding of approximately $1.3M for contractors and consultants (which includes the cost of the tools set forth above) to support the Situation Awareness department in 2017 represents an increase of $84k over 2016 budget levels. The detailed 2017 contractor and consulting budget for the Situation Awareness department is set forth in Exhibit C with a comparison to 2016 budgeted amounts.

[28] FNet – Operated by the Power Information Technology Laboratory at the University of Tennessee, FNET is a low-cost, quickly deployable global positioning system (GPS)-synchronized wide-area frequency measurement network. High dynamic accuracy Frequency Disturbance Recorders (FDRs) are used to measure the frequency, phase angle, and voltage of the power system at ordinary 120 V outlets. The measurement data are continuously transmitted via the Internet to the FNET servers hosted at the University of Tennessee and Virginia Tech.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
SITUATION AWARENESS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 3,624,868	3,624,868	$ 0	$ 3,980,236	$ 355,369	$ 3,906,620	$ 73,616
Penalty Sanctions	67,193	67,193	0	52,485	(14,708)	52,072	413
Total NERC Funding	**$ 3,692,060**	**$ 3,692,060**	**$ 0**	**$ 4,032,721**	**$ 340,661**	**$ 3,958,692**	**$ 74,029**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	1,128	1,128	-	-	-	-
Interest	137	1,816	1,679	140	3	139	1
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 3,692,197**	**$ 3,695,004**	**$ 2,807**	**$ 4,032,862**	**$ 340,664**	**$ 3,958,831**	**$ 74,030**
Expenses							
Personnel Expenses							
Salaries	$ 764,342	$ 787,436	$ 23,094	$ 873,869	$ 109,527	$ 780,907	92,962
Payroll Taxes	58,235	59,443	1,208	58,749	515	59,423	(674)
Benefits	101,765	135,367	33,601	156,328	54,563	142,213	14,115
Retirement Costs	85,275	88,342	3,067	96,159	10,884	90,776	5,382
Total Personnel Expenses	**$ 1,009,617**	**$ 1,070,587**	**$ 60,971**	**$ 1,185,105**	**$ 175,488**	**$ 1,073,320**	**111,785**
Meeting Expenses							
Meetings	$ 6,500	$ 5,000	$ (1,500)	$ 6,500	$ -	$ 6,500	-
Travel	33,005	32,500	(505)	33,005	-	33,005	-
Conference Calls	1,000	1,000	-	305	(695)	305	-
Total Meeting Expenses	**$ 40,505**	**$ 38,500**	**$ (2,005)**	**$ 39,810**	**$ (695)**	**$ 39,810**	**$ -**
Operating Expenses							
Consultants & Contracts	$ 1,211,475	$ 1,268,777	$ 57,302	$ 1,295,850	$ 84,375	$ 1,345,850	(50,000)
Office Rent	-	-	-	-	-	-	-
Office Costs	41,052	39,540	(1,512)	41,897	845	41,897	-
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	7,727	7,727	-	7,667	(60)	7,667	-
Total Operating Expenses	**$ 1,260,754**	**$ 1,316,544**	**$ 55,790**	**$ 1,345,914**	**$ 85,160**	**$ 1,395,914**	**$ (50,000)**
Total Direct Expenses	**$ 2,310,875**	**$ 2,425,631**	**$ 114,756**	**$ 2,570,828**	**$ 259,953**	**$ 2,509,043**	**$ 61,785**
Indirect Expenses	**$ 1,302,775**	**$ 1,391,019**	**$ 88,243**	**$ 1,374,338**	**$ 71,563**	**$ 1,358,187**	**$ 16,151**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 3,613,650**	**$ 3,816,649**	**$ 202,999**	**$ 3,945,167**	**$ 331,516**	**$ 3,867,230**	**$ 77,936**
Change in Assets	**$ 78,547**	**$ (121,645)**	**$ (200,192)**	**$ 87,695**	**$ 9,148**	**$ 91,601**	**(3,906)**
Fixed Assets							
Depreciation	(7,727)	(7,727)	-	(7,667)	60	(7,667)	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 86,273	$ 72,268	(14,005)	95,361	9,088	$ 99,267	(3,906)
Inc(Dec) in Fixed Assets (C)	**$ 78,547**	**$ 64,542**	**$ (14,005)**	**$ 87,695**	**$ 9,148**	**$ 91,601**	**$ -**
TOTAL BUDGET (=B + C)	**$ 3,692,197**	**$ 3,881,191**	**$ 188,994**	**$ 4,032,862**	**$ 340,664**	**$ 3,958,831**	**$ 74,030**
FTEs	**5.53**	**5.70**	**0.17**	**5.64**	**0.11**	**5.65**	**(0.01)**

Event Analysis Department

Event Analysis (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	11.06	11.28	0.22	11.30	(0.02)
Direct Expenses	$ 2,650,065	$ 2,592,388	$ (57,676)	$ 2,686,020	$ (93,631)
Indirect Expenses	2,605,551	2,748,677	143,126	2,716,375	32,302
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	100,179	105,141	4,962	112,953	(7,812)
TOTAL BUDGET	$ 5,355,795	$ 5,446,206	$ 90,411	$ 5,515,347	$ (69,141)

Background and Scope

The Event Analysis department performs assessments of the reliability and adequacy of the BES. This includes identifying potential issues of concern related to system, equipment, entity, and human performance that may indicate a need to develop remediation strategies, action plans, or data used to revise or retire reliability standards or consider new reliability standards. The department analyzes and determines the cause of the events, promptly ensures tracking of corrective actions to prevent recurrence, and provides lessons learned to the industry. Event Analysis ensures that reporting and analysis are consistent to allow wide-area assessment of trends and risks. The department analyzes all reportable events for sequence of events, root cause, risk to reliability, and mitigation and keeps the industry well informed of system events, emerging trends, risk analysis, lessons learned, and expected actions.

Additional resources within this department focus on identifying human-error risks and those precursor factors that allow human error to impact system reliability. The department educates industry regarding risks, precursors, and mitigation methods. Resources also support compliance and standards training initiatives and trending and analysis to identify emerging reliability risks to the BES. These efforts are conducted in collaboration with industry human performance projects, including WECC's Human Performance Working Group, the NERC Operating Committee's Event Analysis Subcommittee, and others.

Stakeholder Engagement and Benefit

The Event Analysis department coordinates event analyses to support the use of collective resources, consistency in analysis, and timely delivery of event analysis reports.[29] The ERO disseminates to the electric industry lessons learned and other useful information obtained from or as a result of event analysis. The Event Analysis team conducts in-depth analyses of approximately 150 events per year on average. In 2014, the team also conducted calls facilitated by the Regional Entities with over 140 registered entities to discuss in detail and finalize root and contributing causes for the categorized events analyzed. Major analysis to date includes continuing assessment of Energy Management System (EMS) outages, continued collaboration with Reliability Assessments and System Analysis on frequency response performance, analyses of substation equipment failure events and protective relay trends including ground overcurrent relay misoperations, relay communication system failures, and the importance of commissioning testing.

Collaboration with the Trade Associations and Forums

The activities of the NATF, the NAGF, trade associations, and other industry groups are expected to compliment ERO Enterprise activities and limit the need to add incremental resources to the NERC and

[29] The core process for Event Analysis is outlined in the approved process: Electric Reliability Organization Event Analysis Process - Version 3 (January 2016).

Regional Entity business plans and budgets that might otherwise be required in the absence of these forums.

NERC is supporting the NAGF's ongoing transformation into a more formal structure through 2017 and continuing through 2018 with logistical and administrative support.

NATF has been invited to participate in several reliability initiatives that are expected to continue into 2017, including protection systems misoperations reduction, physical security, various activities related to reliability assurance initiatives, improvement of modeling practices, and complementary efforts on addressing the GMD challenges.

2017 Goals and Deliverables

In 2017, the Event Analysis department will seek to accomplish several specific goals and objectives as part of the strategic focus of the ERO Enterprise:

- Work with the Regional Entities to obtain and review information from registered entities on qualifying events and disturbances to advance awareness of events above a threshold level; facilitate analysis of root and contributing causes, risks to reliability, wide-area assessments, and remediation efforts; and disseminate information regarding events in a timely manner.
- Ensure that all reportable events are analyzed for sequence of events, root cause, risk to reliability, and mitigation.
- Continue to refine risk-based methods to support better identification of reliability risks, including the use of more sophisticated cause codes for analysis.
- Conduct training (webinars, workshops, and conference support) to inform industry and the ERO of lessons learned, root cause analysis, trends, human performance, and extreme weather preparedness and recommendations.
- Develop reliability recommendations and alerts as needed and track industry accountability for critical reliability recommendations.
- Ensure that industry is well informed of system events, emerging trends, risk analysis, lessons learned, and expected actions.
- Conduct major event analysis and reporting of major findings and recommendations that will improve reliability.

The Event Analysis department will also support several of the top-priority reliability risk projects during 2017 through 2018, as identified and described under the Performance Analysis department section of this document.

Resource Requirements

Personnel

The slight increase in FTEs budgeted in the Event Analysis department in 2017 is due to a lower vacancy rate than in 2016.

Contractor Expenses

No contractor expenses are budgeted in 2017.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
EVENT ANALYSIS

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 5,181,136	$ 5,181,136	$ 0	$ 5,300,955	$ 119,819	$ 5,370,925	$ (69,970)
Penalty Sanctions	134,385	$ 134,385		104,970	(29,415)	104,144	826
Total NERC Funding	**$ 5,315,521**	**$ 5,315,521**	**$ 0**	**$ 5,405,926**	**$ 90,404**	**$ 5,475,069**	**$ (69,143)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	40,000	78,073	38,073	40,000	-	40,000	-
Interest	274	2,918	2,644	281	7	279	2
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 5,355,795**	**$ 5,396,512**	**$ 40,717**	**$ 5,446,206**	**$ 90,411**	**$ 5,515,347**	**$ (69,141)**
Expenses							
Personnel Expenses							
Salaries	$ 1,716,263	$ 1,617,447	$ (98,817)	$ 1,708,049	$ (8,214)	$ 1,778,729	(70,680)
Payroll Taxes	114,132	$ 110,186	(3,946)	108,739	(5,393)	117,316	(8,577)
Benefits	202,259	$ 183,405	(18,853)	212,232	9,973	213,883	(1,651)
Retirement Costs	191,377	$ 180,295	(11,082)	189,397	(1,980)	202,216	(12,819)
Total Personnel Expenses	**$ 2,224,030**	**$ 2,091,333**	**$ (132,698)**	**$ 2,218,416**	**$ (5,614)**	**$ 2,312,144**	**(93,727)**
Meeting Expenses							
Meetings	$ 81,500	$ 140,000	$ 58,500	$ 81,500	$ -	$ 81,500	-
Travel	152,487	152,000	(487)	152,487	-	152,487	-
Conference Calls	14,000	14,000	-	4,270	(9,730)	4,270	-
Total Meeting Expenses	**$ 247,987**	**$ 306,000**	**$ 58,013**	**$ 238,257**	**$ (9,730)**	**$ 238,257**	**-**
Operating Expenses							
Consultants & Contracts	$ 56,000	$ 56,000	$ -	$ -	$ (56,000)	$ -	-
Office Rent	-	-	-	-	-	-	-
Office Costs	49,181	53,576	4,395	49,634	452	49,538	96
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	72,367	85,582	13,214	85,582	13,214	85,582	-
Total Operating Expenses	**$ 178,048**	**$ 195,658**	**$ 17,609**	**$ 135,715**	**$ (42,333)**	**$ 135,619**	**$ 96**
Total Direct Expenses	**$ 2,650,065**	**$ 2,592,990**	**$ (57,075)**	**$ 2,592,388**	**$ (57,677)**	**$ 2,686,020**	**$ (93,631)**
Indirect Expenses	**$ 2,605,551**	**$ 2,511,155**	**$ (94,396)**	**$ 2,748,677**	**$ 143,126**	**$ 2,716,375**	**$ 32,302**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 5,255,616**	**$ 5,104,145**	**$ (151,471)**	**$ 5,341,065**	**$ 85,449**	**$ 5,402,394**	**$ (61,329)**
Change in Assets	**$ 100,179**	**$ 292,367**	**$ 192,188**	**$ 105,141**	**$ 4,962**	**$ 112,953**	**(7,812)**
Fixed Assets							
Depreciation	(72,367)	(85,582)	(13,214)	(85,582)	(13,214)	(85,582)	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 172,546	$ 130,463	(42,083)	190,723	18,176	$ 198,535	(7,812)
Inc(Dec) in Fixed Assets (C)	**$ 100,179**	**$ 44,881**	**$ (55,298)**	**$ 105,141**	**$ 4,962**	**$ 112,953**	**$ (7,812)**
TOTAL BUDGET (=B + C)	**$ 5,355,795**	**$ 5,149,026**	**$ (206,769)**	**$ 5,446,206**	**$ 90,411**	**$ 5,515,347**	**$ (69,141)**
FTEs	**11.06**	**10.29**	**(0.77)**	**11.28**	**0.22**	**11.30**	**(0.02)**

Electricity Information Sharing and Analysis Center (E-ISAC)[30]

E-ISAC (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	18.90	19.74	0.84	19.78	(0.04)
Direct Expenses	$ 11,965,349	$ 12,276,689	$ 311,340	$ 12,501,721	$ (225,032)
Indirect Expenses	4,450,914	4,810,185	359,271	4,753,175	57,009
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	351,262	1,428,467	1,077,205	442,103	986,364
TOTAL BUDGET	$ 16,767,525	$ 18,515,341	$ 1,747,816	$ 17,696,999	$ 818,342

Background and Scope

The Electricity Sector Information Sharing and Analysis Center (ES-ISAC) was formed in 1998 when the U.S. Secretary of Energy requested that NERC serve as the ISAC[31] for the Electricity Subsector.[32] This department was rebranded to the Electricity Information Sharing and Analysis Center (E-ISAC) in September 2015. The E-ISAC reduces cyber and physical risk to the Electricity Subsector across North America by providing unique insights, leadership, and coordination. The vision is to be the trusted, timely, actionable resource of grid risk information and analysis to enhance electricity reliability. The E-ISAC facilitates Electricity Subsector and cross-sector coordination regarding physical security and cybersecurity events affecting the BES.

Maintaining Separation from Compliance and Enforcement

Starting in February 2012, the Board of Trustees approved an E-ISAC Policy Statement that established a separation between the E-ISAC and NERC's compliance and enforcement program. In 2015, physical separation of the E-ISAC was completed. The company also has in place an E-ISAC Code of Conduct and Policy on the Role of the E-ISAC vis-à-vis NERC's Compliance Monitoring and Enforcement Program.

Key Efforts Underway

With industry support, in coordination with the Electricity Subsector Coordinating Council (ESCC) and its Member Executive Committee (MEC), senior management is committed to enhancing the effectiveness and capabilities of E-ISAC operations. These efforts include ongoing enhancement in organizational structure, operational and analytical capabilities, as well as the development of metrics to track the effectiveness of operations. Management will also take steps to improve the quality and value of E-ISAC products, including ongoing review of registered user needs.

During 2015, as part of a periodic review of companywide resource needs and resource allocation, NERC allocated additional resources to support the E-ISAC. Management recruited personnel to fill open positions, and recruited and appointed a senior vice president and chief security officer in charge of E-ISAC operations. Ongoing resource requirements consist primarily of personnel, contractors, consultants,

[30] In 2015, NERC combined its Critical Infrastructure Department (CID) into the E-ISAC for both operational and financial reporting purposes.

[31] The Information Security Analysis Center (ISAC) construct was conceived and operates under US Government authorities derived from Presidential Decision Directive 63, which was signed in 1998. The ISACs focus specifically on information sharing, analytics and sector activities directly related to the protection of critical infrastructure.

[32] Subsequent administrations have sought to continue and strengthen information sharing in other sectors by establishing other sector-specific ISACs. In 2013, the Department of Energy (DOE) again reaffirmed its desire for NERC to continue to operate the E-ISAC.

software, hardware and communications infrastructure to gather, analyze, and provide information regarding cyber and physical security threats.

In the fourth quarter of 2014 and with broad industry support, NERC also assumed management responsibility for the Cybersecurity Risk Information Sharing Program (CRISP). CRISP is a public-private partnership whose purpose is to facilitate the sharing of cyber threat information and to develop situation awareness tools that enhance the electricity sector's ability to identify, prioritize, and coordinate the protection of its critical infrastructure. CRISP provides critical infrastructure owners and operators the capability to voluntarily share cyber threat data, analyze this data, and receive machine-to-machine mitigation measures. Information-sharing devices that are installed on participants' networks send encrypted data to a CRISP analysis center operated by the Pacific Northwest National Labs (PNNL), which analyzes the data it receives and sends alerts and mitigation measures back to CRISP participants and the E-ISAC through secure communications. CRISP became fully operational in 2015. The E-ISAC will continue to work with PNNL, CRISP participants and E-ISAC registered users to strengthen program execution, including both quality and timeliness aspects of information sharing. The 2017 E-ISAC budget maintains the same percentage allocation of CRISP funding requirements from assessments and from CRISP participants as 2016. In connection with the growth of the program and related support needs from E-ISAC staff, the 2017 E-ISAC budget also reflects an increase in the number of budgeted E-ISAC FTEs allocated to support CRISP.

Resource Requirements

Personnel

As previously noted, in 2016 additional open budgeted resources were re-allocated to provide support to the E-ISAC[33], resulting in a net increase of 0.84 FTEs.

The E-ISAC staffing and organizational structure has recently been updated to reflect four primary focus areas (1) stakeholder engagement, (2) watch operations (3) cyber security analysis, and (4) physical security analysis. NERC's 2017 organization chart attached as Appendix 1 has been updated to reflect these changes and additional personnel on-boarded in 2016. The E-ISAC will continue to receive shared services support from NERC's corporate services departments (i.e. finance and accounting, IT, HR, legal and external affairs). Personnel providing such shared services will do so only in accordance with strict operating protocols governing access to and use of E-ISAC information as noted above.

Contract Expenses

The specific nature and need for contract support for the E-ISAC falls under three major categories: Program Level Support, Software and Services, and Events and Outreach. Each of these categories is discussed further below and Exhibit C sets forth the budget for each of these categories of expense.

Program Level Support

CRISP

During 2016 and 2017 NERC will continue to subcontract to PNNL the majority of the resource requirements and associated costs to operate and maintain CRISP.

E-ISAC Portal Enhancement

The E-ISAC communication portal capabilities include: publishing immediate notifications and other informational products, exchanging threat indicator information, and providing self-service access to user

[33] Departments with reduced staffing needs included the legal, enforcement and standards departments.

security awareness services. The E-ISAC is working with NERC Information Technology (in the lead) to continue development of the portal that was initiated in 2014 as part of a long-term improvement strategy. Important new enhancements and improved capabilities are presently in use and development. These include facilitating direct data exchange with E-ISAC members, other ISACs and government partners, and establishing user communities where individuals can discuss security issues. The portal's improved capabilities support E-ISAC analysts in their information analysis functions and directly tie them with their counterparts in other sectors and national laboratories.

In 2015, the ESCC presented its recommendations resulting from a review of the E-ISAC operations performed that year. These recommendations included a request to evaluate and potentially enhance the user interface and underlying functionality of the E-ISAC portal. In 2015, the ESCC established a Member Executive Committee (MEC) to provide guidance with respect to various E-ISAC matters, including improvements to the E-ISAC portal. As part of an approved 2016 work plan, the E-ISAC staff worked closely with the MEC to develop a business case and funding estimates for these improvements. Additional details summarizing the business case, funding estimate and additional detail regarding the portal improvement project is attached as Exhibit F.

The 2017 E-ISAC budget includes $1M for the portal enhancements ($250,000 of which is allocated to CRISP)[34]. The MEC has provided written comments [found here] in support of this investment.

Additional portal enhancements in 2016 and 2017 will also extend functionality to allow for easier access to filtered data for both the cyber and physical security communities and provide for automated information sharing. Based on input from users, the E-ISAC is transitioning the current portal capability to a platform model that will provide features and extensions beyond what can currently be delivered with the existing portal. Some of the new features will include user customization, visual and graphical orientation (versus text-based), robust search and structured queries, and the ability to create on-the-fly technical analysis of information shared by users. This will be a multi-year project that will evolve as users engage the new capabilities and provide feedback. In 2017 the E-ISAC and NERC IT plan to launch the initial platform prototype with new capabilities, then add capabilities and features in 2018 and subsequent years as needed.

Software and Services

Software Integration Support Services

The E-ISAC operations center includes monitors used to display intelligence information provided from various software applications. Software integration services are routinely required from vendors providing existing and new software applications. Additional software must be licensed and maintained to display and integrate BES maps that have cyber intelligence information. A portion of these costs is budgeted under Office Costs as software maintenance expenses.

Analyst Workbench

A strong technical analytic capability is needed to develop baselines and identify patterns and understandings of potential cyber-related threats. The analyst workbench toolset maintains historical information and allows a team to use and deliver consistent and repeatable analysis in both an operational (during an event) as well as nonoperational capacity. This workbench will include a threat database for historical correlation and various tools for network- and host-based analysis of malicious software.

[34] The annual impact of the proposed $1M investment on assessments will be approximately $250,000 since projects of this nature are typically financed through NERC's capital financing program and funded over a three year period.

Automated Information Sharing

The E-ISAC is broadening automated information sharing beyond CRISP, looking at programs such as the Structured Threat Information Expression/Trusted Automated Exchange of Indicator Information (STIX/TAXII) initiative hosted by the US Department of Homeland Security. As part of a work plan developed in consultation with the MEC, in 2016 the E-ISAC plans to pilot and gather data on these technologies, leveraging existing implementations at Argonne National Lab. The pilot will help the E-ISAC understand the nuances of bi-directional communication, workflow, handling rules, vetting information, and learning from the technology and processes overall. The E-ISAC aims to have seven members signed up by the end of 2016, and, assuming the 2016 pilot is successful, another 10 members sign up in by the end of 2017.

Events and Outreach

Grid Security Exercises

Since 2011, NERC has sponsored a series of biennial grid security exercises (GridEx). These geographically distributed exercises are designed to exercise the electricity sector's crisis response to simulated coordinated cybersecurity and physical security threats and incidents, to strengthen utilities' crisis response functions, and to provide input for lessons learned. GridEx III, in November 2015, consisted of a two-day grid-focused operational exercise for participants across North America and a half-day tabletop discussion for executives. The E-ISAC manages the program and collects industry information during and after the exercise subject to existing data collection policies. During the exercise, E-ISAC watch and analysis staff exercise the E-ISAC mission and share severe crisis information sharing and analysis towards mitigating the threats and attacks. Lessons learned and recommendations are turned over to groups like NERC's Board of Trustees and CIPC and to the ESCC for consideration and coordination between industry and government stakeholders. GridEx IV is scheduled for November 15-16, 2017.

Grid Security Conferences

Since 2011, NERC has sponsored a series of annual grid security conferences (GridSecCon). These conferences bring together industry and government subject matter experts on cyber, physical and operations technology threats and solutions, with training sessions and classified or official use briefs on topics vital to grid security. The E-ISAC provides expertise and gathers appropriate speakers, panelists and training providers. GridSecCon 2016 is scheduled for October 18-21 in Quebec, Canada, with the 2017 location and dates TBD.

Intelligence Reporting Services

E-ISAC analytic personnel maintain a detailed understanding of emerging vulnerabilities and threats within the broad industrial control systems community, as well as within the more focused BES community. To support this intelligence role, the E-ISAC budget includes the costs for intelligence services from a specialized security information service providers that focuses closely on the electricity subsector. This service gives E-ISAC staff increased understanding of continuing trends, breaking news, and implications to the BES, which they utilize to keep registered entities informed of emerging BES risks through immediate notifications and portal security postings.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection and 2017 Budget
E-ISAC

	2016 Budget	2016 Projection	2016 Projection v 2016 Budget Over(Under)	2017 Budget	2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 9,636,756	9,636,756	$ (0)	$ 11,270,705	$ 1,633,948	$ 10,533,578	$ 737,127
Penalty Sanctions	229,563	229,563	0	183,698	(45,865)	182,233	1,465
Total NERC Funding	**$ 9,866,319**	**$ 9,866,319**	**$ (0)**	**$ 11,454,403**	**$ 1,588,084**	**$ 10,715,811**	**$ 738,592**
Third-Party Funding (CRISP)	6,830,738	7,335,757	505,019	6,990,447	159,709	6,910,701	79,746
Workshops	70,000	70,000	-	70,000	-	70,000	-
Interest	468	-	(468)	491	24	487	4
Total Funding (A)	**$ 16,767,525**	**$17,272,076**	**$ 504,551**	**$ 18,515,341**	**$ 1,747,816**	**$ 17,696,999**	**$ 818,342**
Expenses							
Personnel Expenses							
Salaries	$ 3,373,066	$ 3,242,857	$ (130,209)	$ 3,417,398	$ 44,332	$ 3,391,165	$ 26,234
Payroll Taxes	208,610	193,941	(14,668)	204,023	(4,587)	209,345	(5,322)
Benefits	345,260	315,363	(29,897)	397,467	52,207	384,714	12,754
Retirement Costs	366,723	351,531	(15,192)	363,482	(3,241)	372,179	(8,697)
Total Personnel Expenses	**$ 4,293,659**	**$ 4,103,693**	**$ (189,966)**	**$ 4,382,370**	**$ 88,711**	**$ 4,357,402**	**$ 24,968**
Meeting Expenses							
Meetings	$ 230,000	$ 229,000	$ (1,000)	$ 230,000	$ -	$ 230,000	$ -
Travel	256,488	237,455	(19,032)	256,488	-	256,488	-
Conference Calls	22,000	23,000	1,000	6,710	(15,290)	6,710	-
Total Meeting Expenses	**$ 508,488**	**$ 489,455**	**$ (19,032)**	**$ 493,198**	**$ (15,290)**	**$ 493,198**	**$ -**
Operating Expenses							
Consultants & Contracts	$ 6,551,929	$ 7,579,159	$ 1,027,230	$ 6,788,429	$ 236,500	$ 7,038,429	$ (250,000)
Office Rent	-	$ -	-	-	-	-	-
Office Costs	392,285	$ 296,103	(96,182)	431,895	39,610	431,895	-
Professional Services	175,000	$ 175,000	-	175,000	-	175,000	-
Miscellaneous	500	$ 500	-	500	-	500	-
Depreciation	43,489	$ 45,998	2,509	5,297	(38,192)	5,297	-
Total Operating Expenses	**$ 7,163,203**	**$ 8,096,760**	**$ 933,557**	**$ 7,401,121**	**$ 237,919**	**$ 7,651,121**	**$ (250,000)**
Total Direct Expenses	**$ 11,965,349**	**$12,689,908**	**$ 724,559**	**$ 12,276,689**	**$ 311,340**	**$ 12,501,721**	**$ (225,032)**
Indirect Expenses	**$ 4,450,914**	**$ 4,601,898**	**$ 150,984**	**$ 4,810,185**	**$ 359,271**	**$ 4,753,175**	**$ 57,009**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 16,416,263**	**$17,291,806**	**$ 875,543**	**$ 17,086,873**	**$ 670,610**	**$ 17,254,896**	**$ (168,023)**
Change in Assets	**$ 351,262**	**$ (19,730)**	**$ (370,992)**	**$ 1,428,467**	**$ 1,077,205**	**$ 442,103**	**$ 986,364**
Fixed Assets							
Depreciation	(43,489)	(45,998)	(2,509)	(5,297)	38,192	(5,297)	-
Computer & Software CapEx	100,000	111,722	11,722	1,100,000	1,000,000	100,000	1,000,000
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	41,958	41,958	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 294,751	$ 248,373	(46,378)	333,765	39,014	347,401	(13,636)
Inc(Dec) in Fixed Assets (C)	**$ 351,262**	**$ 356,054**	**$ 4,792**	**$ 1,428,467**	**$ 1,077,205**	**$ 442,103**	**$ 986,364**
TOTAL BUDGET (=B + C)	**$ 16,767,525**	**$17,647,860**	**$ 880,335**	**$ 18,515,341**	**$ 1,747,816**	**$ 17,696,999**	**$ 818,342**
FTEs	**18.90**	**18.95**	**0.05**	**19.74**	**0.84**	**19.78**	**(0.04)**

Training, Education, and Operator Certification

Training, Education and Operator Certification (in whole dollars)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget -Prior Draft	Variance to Prior Draft Over(Under)
Total FTEs	7.38	7.05	(0.33)	7.07	(0.01)
Direct Expenses	$ 2,062,086	$ 1,922,295	$ (139,791)	$ 1,889,814	$ 32,481
Indirect Expenses	1,737,034	1,717,923	(19,111)	1,697,734	20,189
Other Non-Operating Expenses	-	-	-	-	-
Inc(Dec) in Fixed Assets	113,112	117,283	4,171	122,165	(4,882)
TOTAL BUDGET	$ 3,912,231	$ 3,757,501	$ (154,731)	$ 3,709,713	$ 47,788

Background and Scope

NERC's Training and Education Program provides oversight and coordination of the delivery of training programs that support the ERO's statutory responsibilities. This program provides training to NERC and Regional Entity staff members. It also provides training and education to industry participants on the requirements of reliability standards and the compliance monitoring and enforcement process. Further, this program provides training to industry participants on NERC's reliability standards development process, thereby helping to support the more efficient and effective development of mandatory reliability standards. The Training and Education Program supports NERC's responsibilities to develop, adopt, and obtain approval of reliability standards and to monitor, enforce, and achieve compliance with the mandatory standards. Section 901 of the NERC Rules of Procedure addresses the Training and Education Program's activities. The responsibility for training is shared among multiple departments at NERC.[35]

NERC's System Operator Certification program, which ensure that personnel operating the BES have the skills, training, and qualifications needed to operate the system reliably. NERC maintains the required credentials for over 6,000 system operators to work in system control centers across North America. NERC's system operator certification exam is designed to test specific knowledge of job skills and reliability standards. It also prepares operators for complying with requirements of reliability standards and appropriately operating the BES during normal and emergency operations. The System Operator Certification Program is governed by the Personnel Certification Governance Committee (PCGC), an industry group of operations experts, trainers, and supervisors. Certification exams are created by the Exam Working Group (EWG), an industry group of operations subject matter experts. Under the PCGC oversight, the EWG reviews and updates job tasks and certification exams. Section 600 of the NERC Rules of Procedure addresses the Personnel Certification activities in the area of Operator Certification.

Once an operator passes the certification exam, certification is maintained by completing NERC-approved continuing education courses and activities. The Personnel Subcommittee, composed of industry training experts, provides oversight of the Continuing Education program. Section 902 of the NERC Rules of Procedure addresses the Continuing Education Program's activities in these areas.

Key Efforts Underway

The ERO provides education for industry and ERO Enterprise staff personnel to support their understanding of key program areas. These areas include:

[35] The Human Resources department is also engaged in training initiatives.

1. Risk-Based Compliance Monitoring and Enforcement
2. Standards and Compliance
3. Registration and Certification
4. Event Analysis, Cause Analysis, and Lessons Learned
5. Reliability Assessment and System Analysis
6. Continuing education for system operators
7. New System Operator Certification exams for each credential: Reliability Coordinator; Transmission Operator; Balancing and Interchange Operator; and Balancing, Interchange and Transmission Operator.

2017 Goals and Deliverables

In response to stakeholder and Regional Entity feedback, training and education opportunities will be further expanded and focused for registered entities, NERC staff, and Regional Entities. For registered entities, this training and education will focus on objectives related to NERC reliability standards, including standards compliance and emerging cyber-related issues that could affect BES reliability. For NERC and Regional Entity staff, the training and education will focus on consistent audit and investigation techniques and standards compliance reviews, including the risk-based compliance monitoring and enforcement and other improvements in compliance and enforcement practices. NERC will continue to offer training in auditor skills to promote continued development of auditing expertise. NERC will leverage IT systems to better deliver and share common training products and information with Regional Entities and registered entities. Other training will focus on knowledge and skill development in a number of key areas, including:

- Development and implementation of clear and technically sound reliability standards
- Key lessons learned and trends from events
- Identified themes from trending and common-cause analyses
- Effective compliance cultures with practices, procedures, and controls to address reliability risks
- Effective root, apparent, and common-cause analysis methods
- Quality improvement of registered entity self-reporting and self-certification
- Entity registration processes, issues, and alternatives
- Human performance fundamentals
- Developing and incorporating a systematic approach to ongoing training

NERC will continue to provide learning opportunities through workshops hosted by the Regional Entities. NERC will also host workshops, webinars, and training courses, as well as use vendors to develop training modules and supplement internal training resources. The responsibility for the subject matter expertise for much of the training is shared among multiple departments at NERC. The Training and Education group will provide coordination and synchronization efforts for shared NERC and ERO training responsibilities in addition to advancing and improving the skills of NERC's operating staff. NERC's Human Resources department will continue to budget and manage the delivery of more traditional corporate employee training and continuing education programs in concert with the coordination and synchronizing efforts of the Training and Education group.

As part of the System Operator Certification exam development cycle, the results of the 2015 job task analysis (JTA) is the baseline for the upcoming set of exams. The EWG will continue to analysis new items and develop a cut score for the pending 2018 exams.

Key deliverables for the System Operator Certification Program:

- Complete analysis of exam Item Bank
- Implementation of Linear On the Fly (LOFT) testing for all exams

NERC will continue to work with industry stakeholders and the exam development vendor to create certification exams that will promote reliability of the North American BPS.

The Continuing Education (CE) program will evaluate and revise the current program criteria as reflected in the program manual. The evaluation will consider the growth and maturation of industry training programs as well as ongoing research in the area of adult learning to ensure the CE program continues to foster improvement of training and promotes quality in training programs.

Resource Requirements

Personnel
No additional personnel are proposed for this area in 2017.

Contractor Expenses
The total proposed consulting and contractor budget is approximately $95k lower in 2017 than the 2016 budget.

Further detail in support of the proposed 2017 contractor and consulting budget to support Training, Education, and Operator Certification is set forth in Exhibit C, which includes a comparison to 2016 budgeted amounts. The primary areas of contractor and consulting support include:

- Testing services to develop, administer, proctor, score, and support system operator certification exams across North America.
- Ongoing hosting and maintenance fees for the System Operator Certification and Continuing Education (SOCCED) database.
- Improvements to the SOCCED database.
- Supplemental support to Continuing Education Review Panel industry volunteers to review and audit over 2,500 individual learning activities and provider applications received each year.[36]
- Audit team leader soft skills training delivered by certified NERC staff using vendor-licensed materials to support effective dialogue and communications between audit teams and registered entities.
- Vendor-supported BES technical training for select ERO staff, including compliance, technical and support staff.
- Risk-based compliance training by recognized specialists for NERC and Regional Entity staff to promote continued development of compliance staff.

[36] Review and approval of learning activity applications results in over 400,000 hours of continuing education per year for the industry's certified system operators.

- Web-based training development for ERO staff and industry, including standards applications, risk assessment training, industry human performance fundamentals, and BES events lessons learned.
- An ERO Enterprise learning management system to support scheduling, computer-based training delivery and record maintenance for ERO and select Enterprise staff.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
TRAINING, EDUCATION and OPERATOR CERTIFICATION

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 1,742,146	$ 1,742,146	$ 0	$ 1,822,089	$ 79,944	$ 1,820,199	$ 1,890
Penalty Sanctions	55,994	55,994	$ -	43,738	(12,256)	43,393	344
Total NERC Funding	**$ 1,798,139**	**$ 1,798,139**	**$ 0**	**$ 1,865,827**	**$ 67,687**	**$ 1,863,592**	**$ 2,235**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	1,867,972	1,867,972	-	1,921,900	53,928	1,921,900	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	183	2,096	1,913	175	(7)	174	1
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 3,666,294**	**$ 3,668,207**	**$ 1,913**	**$ 3,787,902**	**$ 121,608**	**$ 3,785,666**	**$ 2,236**
Expenses							
Personnel Expenses							
Salaries	$ 857,257	$ 849,104	$ (8,153)	$ 852,091	$ (5,166)	$ 845,520	6,570
Payroll Taxes	64,345	65,293	948	62,727	(1,619)	63,717	(990)
Benefits	133,991	114,786	(19,205)	139,239	5,248	116,375	22,864
Retirement Costs	94,860	97,129	2,268	97,624	2,764	98,587	(963)
Total Personnel Expenses	**$ 1,150,454**	**$ 1,126,312**	**$ (24,142)**	**$ 1,151,681**	**$ 1,227**	**$ 1,124,199**	**27,481**
Meeting Expenses							
Meetings	$ 80,000	$ 55,000	$ (25,000)	$ 55,000	$ (25,000)	$ 55,000	-
Travel	21,139	19,900	(1,239)	21,139	-	21,139	-
Conference Calls	36,500	36,500	-	11,133	(25,368)	11,133	-
Total Meeting Expenses	**$ 137,639**	**$ 111,400**	**$ (26,239)**	**$ 87,272**	**$ (50,368)**	**$ 87,272**	**-**
Operating Expenses							
Consultants & Contracts	$ 675,800	$ 731,460	$ 55,660	$ 580,600	$ (95,200)	$ 580,600	-
Office Rent	-	-	-	-	-	-	-
Office Costs	95,773	104,935	9,161	100,323	4,550	95,323	5,000
Professional Services	-	-	-	-	-	-	-
Miscellaneous	500	500	-	500	-	500	-
Depreciation	1,919	1,919	-	1,919	-	1,919	-
Total Operating Expenses	**$ 773,992**	**$ 838,814**	**$ 64,821**	**$ 683,342**	**$ (90,650)**	**$ 678,342**	**$ 5,000**
Total Direct Expenses	**$ 2,062,086**	**$ 2,076,525**	**$ 14,440**	**$ 1,922,295**	**$ (139,791)**	**$ 1,889,814**	**$ 32,481**
Indirect Expenses	**$ 1,737,034**	**$ 1,810,570**	**$ 73,536**	**$ 1,717,923**	**$ (19,111)**	**$ 1,697,734**	**$ 20,189**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Total Expenses (B)	**$ 3,799,119**	**$ 3,887,096**	**$ 87,976**	**$ 3,640,218**	**$ (158,901)**	**$ 3,587,548**	**$ 52,670**
Change in Assets	**$ (132,825)**	**$ (218,888)**	**$ (86,063)**	**$ 147,684**	**$ 280,510**	**$ 198,118**	**(50,434)**
Fixed Assets							
Depreciation	(1,919)	(3,838)	-	(1,919)	-	(1,919)	-
Computer & Software CapEx	-	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-	-
Allocation of Fixed Assets	$ 115,031	$ 103,360	(11,671)	119,202	$ 4,171	$ 124,084	(4,882)
Inc(Dec) in Fixed Assets (C)	**$ 113,112**	**$ 99,522**	**$ (11,671)**	**$ 117,283**	**$ 4,171**	**$ 122,165**	**$ -**
TOTAL BUDGET (=B + C)	**$ 3,912,231**	**$ 3,986,618**	**$ 76,305**	**$ 3,757,501**	**$ (154,731)**	**$ 3,709,713**	**$ 47,788**
FTEs	**7.38**	**7.39**	**0.01**	**7.05**	**(0.33)**	**7.07**	**(0.01)**

Administrative Services

Administrative Services (in whole dollars)	Direct Expenses and Fixed Assets			FTEs						
	2016 Budget	2017 Budget	Increase (Decrease)	2016 Budget	2017 Budget	Increase (Decrease)	2017 Budget - Prior Draft	Draft Over(Under)	2017 FTE -Prior Draft	Prior Draft Over(Under)
General and Administrative	$ 9,881,311	$ 10,205,977	$ 324,666	17.52	16.92	(0.60)	10,048,346	157,631	16.01	0.91
Legal and Regulatory	3,465,966	3,292,379	(173,587)	12.22	11.28	(0.94)	$ 3,370,002	(77,623)	12.25	(0.97)
Information Technology	12,156,674	12,480,846	324,171	22.13	23.27	1.14	$ 12,448,188	32,658	23.31	(0.05)
Human Resources	1,510,177	1,608,583	98,406	2.77	2.82	0.05	$ 1,684,684	(76,102)	3.77	(0.95)
Finance and Accounting	3,428,307	3,827,050	398,743	16.60	15.04	(1.56)	$ 3,844,269	(17,219)	16.01	(0.97)
Total Administrative Services	**$ 30,442,435**	**$ 31,414,834**	**$ 972,399**	**71.23**	**69.33**	**-1.91**	**$ 31,395,489**	**19,345**	**71.36**	(2.03)

Program Scope and Functional Description

NERC's Administrative Services area includes the budget for all business and administrative functions of the organization, including (1) technical committees and member forums; (2) General and Administrative, which includes Board fees and expenses, the president and chief executive officer (CEO), chief reliability officer (CRO) and support staff, communications, external affairs and governmental relations, and office rent; (3) Legal and Regulatory; (4) Information Technology; (5) Human Resources; (6) Finance and Accounting; and (7) other general administrative expenses necessary to support program area activities. These functions are necessary to the existence and functioning of the organization and support the performance of NERC's ERO statutory activities. The costs of the Administrative Services functions are allocated to the five statutory programs as indirect expenses. The resource requirements and comparative budget information for each of these functions are described below.

Technical Committees and Members' Forum Program

While NERC management and staff will continue to interact with and support numerous reliability-related forums (e.g., the North American Transmission Forum and Generator Forum), NERC's 2017 budget does not contain specific funding for any forum activities.

General and Administrative

Background and Scope

The General and Administrative area is responsible for the administration and general management of the organization. Expenses allocated in this area include office rent; personnel and related costs of the CEO, the CRO, the CEO's executive assistant, communications, external affairs and government relations staff, and costs related to the Board. No additional personnel are budgeted for 2017 beyond current staffing. The increase in FTEs in the General and Administrative area is due to a reallocation occurring in 2016 of personnel supporting the Member Representatives Committee and Regional Entity Management Group activities.

The following table details the Board costs included in the total costs of the General and Administrative area.

Board of Trustee Expenses	Budget 2016	Projection 2016	Budget 2017	2017 v 2016 Budget	Variance %
Meetings and Travel Expenses					
Quarterly Board Meetings	$ 244,000	$ 244,000	$ 244,000	$ -	
Trustee Travel	150,000	150,000	150,000	-	
Total Board of Trustees Meetings and Travel Expenses	**$ 394,000**	**$ 394,000**	**$ 394,000**	**$ -**	
Professional Services				-	
Independent Trustee Fees	$ 1,126,354	$ 1,126,354	$ 1,226,000	$ 99,646	
Trustee Search Fees	100,000	100,000	100,000	-	
Total Board of Trustee Professional Services Expenses	**$ 1,226,354**	**$ 1,226,354**	**$ 1,326,000**	**$ 99,646**	**8.13%**
Total Board of Trustee Expenses	**$ 1,620,354**	**$ 1,620,354**	**$ 1,720,000**	**$ 99,646**	**6.15%**

Legal and Regulatory

Background and Scope

The Legal and Regulatory department's workload is derived from the following key NERC program areas: Compliance Analysis and Certification and Registration, Reliability Risk Management, Reliability Assessment and Performance Analysis, and Standards. In addition, the Legal and Regulatory department is also responsible for providing a wide range of legal support to the NERC management team regarding antitrust, corporate, commercial, insurance, contract, employment, real estate, copyright, tax, legislation, and other legal matters. The department also addresses legal and regulatory matters that arise in connection with the delegation agreements with the Regional Entities.

Resource Requirements

Due to process improvements and increased efficiency, the number of FTEs allocated to the department was reduced in 2017 compared to 2016.

Outside law firms and consultants supporting this area are budgeted and tracked as Professional Services. The Professional Services budget for 2017 was reduced by approximately 25% compared to the 2016 budget.

Information Technology

Background and Scope

NERC's IT department plan includes capital and operating expenses required to support, build, configure, and enhance applications that serve registered entities, Regional Entities, and NERC staff. The plan also includes work related to ERO Enterprise data analysis, as well as ongoing NERC internal operations.

The focus of the 2017 – 2019 budget places a heavy emphasis on applications and data analytics designed to improve and enhance the efficiency and productivity of NERC and the Regional Entities, and support more consistent and streamlined interactions with registered entities. These investments will provide broad benefits across the ERO Enterprise in terms of the efficiency and effectiveness of operations and meeting our reliability goals. Additionally, by working to provide more services to the Regional Entities in terms of tools and systems, associated economies of scale will result in these initial investments providing increasing value across the ERO Enterprise in the years to come.

The budget is broken down into four categories as follows:

1. **ERO Enterprise New Functionality –** Items listed in this category are those items designed to add, enhance, or improve, capabilities for registered entities, Regional Entities, and NERC staff. This includes items such as Enterprise Reporting, data analytics and warehousing, the Misoperation

Information Data Analysis System (MIDAS), User Management and Registration (UMR), and the Generating Availability Data System for Wind Turbine Generation (GADS Wind).

2. **ERO Enterprise Infrastructure & Support –** Items listed in this category are those infrastructure and support items required for applications used by registered entities, Regional Entities, and NERC staff. Items include The Events Analysis Management System (TEAMS), the Bulk Electric System Notification and Exception System tool (BESnet), the Standards Balloting System (SBS), the Reliability Coordinator Information System (RCIS), and numerous other applications.
3. **NERC New Functionality –** Items in this category are those items that enhance or improve the internal NERC infrastructure, such as Document Management, telephony, and audio visual.
4. **NERC Infrastructure & Support –** Items listed in this category are primarily those items required to maintain and run the internal office infrastructure, and support NERC staff operations. Items include server hardware and software licenses, network equipment, data and telecommunication circuits, and data storage, as well as office administrative applications (e.g., Microsoft Office) and user hardware such as laptops and peripherals.

A further discussion of each item is outlined below:

ERO Enterprise New Functionality:
As noted above, this category is primarily those applications or systems designed to improve or add capability to registered entities, Regional Entities, and NERC staff. Over the past two years, IT has been successful at deploying a number of new applications and functionality for the ERO Enterprise that have now moved into support. In 2017 and beyond, IT will continue that trend with a heavy focus on data and analytics.

a. Enterprise Reporting. In 2015, IT was successful at providing Enterprise Reporting Phase 1 and 2. In the latter part of 2016, IT will bring generation performance data into the Enterprise Reporting system. In 2017 and subsequent budget planning years IT will focus on additional datasets, as well as increasing the analytical and data mining capabilities for the ERO Enterprise.

b. Entity Registration. In 2016, IT began an effort to replace its existing "User Management Program" customer relationship management tool with one based on Microsoft Dynamics CRM (xRM). In 2017, that effort will be extended by integrating the compliance registration function into the xRM system, including implementation of the "common registration form." This will result in a common registration system shared across the ERO Enterprise that provides a consistent user experience for registered entities.

c. Compliance Monitoring and Enforcement Process Tools. IT will also work closely with the Regional Entities in 2017 to evaluate and implement strategic investments in tools that support the Compliance Monitoring and Enforcement Process. Items under consideration at this time include how NERC and the Regional Entities manage registered entity information (and how that information integrates with Enterprise Reporting to provide reliability risk analysis functionality), how Reliability Standards data is stored and maintained, and how best to support the various parts of the compliance and enforcement process (e.g., analysis of risk, development of implementation plans and audit schedules, actual compliance monitoring, and enforcement processing). Funding for any capital investments in new Enterprise Compliance and Monitoring Tools will be subject to review and approval as part of the business plan and budget application to the year when such investments are proposed to be made.

d. Extranet Development – NERC IT currently provides external collaboration function through the use of secure WebDAV folders and limited deployment of Microsoft SharePoint. In 2017, IT will

develop a more robust implementation of SharePoint to provide better services and support for collaboration across the ERO Enterprise and with stakeholders.

ERO Enterprise Infrastructure & Support:
This line item primarily consists of items used by registered entities, Regional Entities, and NERC Staff. During 2015, and 2016, IT, worked closely with the Regional Entities to design and configure a number of ERO Enterprise applications, with a bias toward using Commercial-off-the-Shelf (COTS) technology whenever possible. Infrastructure and support for these COTS tools (such as SharePoint and the Dynamics xRM platform), as well as custom built applications developed in the past, require ongoing investment to maintain continuous operations. For many applications and systems, this includes the cost of maintaining development, quality assurance, and staging and production environments, which are required to ensure the security and operational integrity and stability of the multiple applications supported for the ERO Enterprise. These applications and systems are monitored, tested (including penetration and vulnerability testing), and maintained in a manner as to ensure the highest level of integrity, security, and availability to the roughly 4,000 users across North America.

In 2016, IT placed emphasis on ensuring the environment was configured in a manner consistent with enterprise best practices, ensuring the security and integrity of the environment while allowing ERO Enterprise users to obtain the information and resources required to perform various analyses. Ongoing support for applications such as TEAMS, MIDAS, SBS, the Reliability Analysis Data System (RADS), in addition to numerous legacy ERO Enterprise products, make up this portion of the IT budget.

NERC New Functionality:
Items included in this category are primarily those items designed to improve, enhance, or replace existing functionality for internal NERC staff and, generally speaking, are not consumed by ERO Enterprise clients.

a. **Document Management Program and Intranet Enhancement** – During 2015 and 2016, NERC began implementation of a document management system, leveraging SharePoint 2013 as the foundational platform. The implementation of a document management program supports a number of important business requirements, including:

   - Ensuring proper classification and management of confidential information
   - Addressing a number of internal audit recommendations/mitigating corporate risk
   - Improving information access and search capabilities
   - Facilitating working group, team, and stakeholder collaboration
   - Supporting document retention policy and procedures
   - Simplifying document retrieval
   - Improving version control of documents
   - Improving workflow control (review and approval of documents)
   - Increasing efficiency and employee productivity

   Two additional products were integrated as part of this effort: Gimmal Compliance Suite, an add-on to SharePoint, which enables robust records management capabilities, and Repstor Affinity, which enables offline visibility into content repositories via Microsoft Outlook. In 2016, NERC will implement document management for six program areas. In 2017, NERC will bring the remaining program areas online. The implementation of a document management system is a multi-year initiative designed to greatly reduce the manual and labor-intensive

effort of managing thousands of documents by streamlining the storage, security, versioning, data classification, and archiving of NERC information.

b. **Audio Visual –** During 2016, IT will replace audit visual (AV) equipment in NERC's primary conference rooms with a Cisco WebEx solution designed to enhance capability (e.g. video conferencing), in addition to reducing cost of travel, when possible. In 2017, as appropriate and approved, additional conference rooms will be refreshed with AV equipment.

c. **IT Infrastructure Services** – During 2016, IT undertook an initiative to leverage qualified vendors for sourceable work, allowing IT to place a greater emphasis on ERO Enterprise projects. Network monitoring is one example of where we have been successful in moving items such as monitoring to a qualified vendor. While technically not "new" capability, implementation of this new approach to network monitoring allows NERC's internal IT resources to focus on larger initiatives designed to serve the ERO Enterprise. IT will continue to pursue this strategy in 2017 as additional work is identified that can be efficiency and cost effectively assumed by qualified vendors.

d. **Public Facing Website Improvements** - Over the past several years, NERC has routinely made updates to its outward-facing Internet presence, during which technology improvements are made and suggestions and requests are implemented. In 2017, IT will work with the company's communications department to begin a project to review the information architecture of the NERC.com site and make changes with the goal of providing a more streamlined user experience.

NERC Infrastructure & Support

As previously noted, NERC Infrastructure & Support are those items required to maintain and support the internal infrastructure for NERC staff. Items such as file servers, network equipment, storage, Microsoft Office (Word, Excel, PowerPoint, Email, SharePoint, etc.), along with security and telecommunications are required to ensure staff have the necessary tools and technology to perform their daily operational functions. Emphasis in 2017 and in the 2018 – 2019 planning cycle will continue to work toward optimizing the amount of effort placed on NERC infrastructure and support to minimize spend on internal office steady state operations, allowing a larger portion of IT resources to focus on new ERO Enterprise functionality, as well as ERO Enterprise infrastructure and support. Examples of items included in internal operations are outlined below**:**

a. **Compliance Reporting and Tracking System (CRATS)** – This compliance database is used to track violations, mitigation plans, and reporting required by NERC as the certified ERO. In addition, the compliance database has additional modules included, such as the Standards, Technical Feasibility Exceptions (TFEs), and Registration module, which contains a list of all registered entities. Funding requirements include ongoing maintenance and enhancements to the CRATS compliance tools.

b. **Meeting Manager, ERO Membership, RCIS, Central Repository of Curtailment Events (CRC)** – NERC maintains a number of legacy applications. Many of the legacy applications were developed and implemented five to ten years ago and are unable to benefit from contemporary application development. Some may have to be completely rewritten, or moved to the xRM application platform, as IT was able to do with Application Broker, NERC MyAccount and UMP in 2016. Funding in 2017 is required for ongoing maintenance and enhancements until the applications can be rewritten or moved to the xRM platform or, in some cases, potentially divested or transferred to industry support.

c. **Quarterly Penetration and Vulnerability Testing All NERC Networks and Systems** – Expert consulting services to provide ongoing intrusion detection and vulnerability testing of the

NERC public website, NERC's network, applications, and systems is an essential requirement of ongoing operations. NERC is subject to frequent intrusion attempts where external parties try to gain access to our systems and infrastructure. Any vulnerability identified is documented and provided to NERC IT for rapid remediation.

d. **NERC Security Program -** NERC's IT department performs a number of technology initiatives to ensure the security of the network and infrastructure. However, in order to continually improve security, a more holistic approach is required that implements technology improvements and constructs an overarching security program to ensure all aspects of security have been considered, including information classification, review of retention policies, and enforcement of security guidelines. During 2016, IT undertook an initiative to improve several processes and will continue to place a high emphasis on security over the coming years.

Robust Planning for New Capital Projects

In connection with the 2016 business planning cycle, the company significantly improved its approach to evaluating potential capital investments in major enterprise software applications. The company has adopted an enterprise information technology investment planning methodology that ensures only projects with compelling and approved business cases are funded. The approval process uses a four approval gates:

- A Business Unit Sponsor approval gate,
- A NERC VP/CTO approval gate,
- An ERO Technology Leadership Team (comprised of the NERC CEO and two Regional Entity CEOs) approval gate, and
- The full ERO-EMG (CEOs of NERC and each Regional Entities) approval gate.

This gated process provides the required rigor and discipline to ensure only high value enterprise IT investments are pursued. In addition, all Enterprise IT investments are subject to ongoing oversight by a subgroup consisting of four members of the Board's Standards Oversight and Technology Committee. The company will continue to use this process for the 2017 – 2019 budget planning cycle.

Examples of the results of this methodology in 2016 include investments in TEAMS and the RADS.

TEAMS. The TEAMS application provides integration of events data systems, while enabling a more efficient and effective method for event data collection, tracking, analysis and reporting. This enhances the ability of the ERO and stakeholders to identify and focus on significant and emerging reliability risks. This tool is used by NERC and the Regional Entities, providing a consistent experience for all ERO clients involved in the events analysis business process. The benefits provided by the TEAMS application streamline ERO Enterprise reliability data sources with an event data collection platform that is consistent with the event analysis process. Benefits include:

- **Improving Efficiency:** TEAMS helps ensure the reliability of the Bulk Power System by facilitating:
  - The reporting of a BPS event
  - The evaluation of BPS events
  - The undertaking of appropriate levels of EA
  - The generation of lessons learned

  - The generation of reliability trend analysis

- **Managing Reliability Risk:** TEAMS enables the ERO Enterprise to integrate event reports with other reliability data sources and develop portfolios of risk information. This integration enables a more complete analysis into the cause of events, including transmission outages, generation trips, and load loss. With this analysis, the ERO Enterprise can better identify unplanned service interruptions and spotlight key areas for reliability improvement, with the ultimate goal of reducing the probability and reliability impact of future system events.
- **Fostering Collaboration:** Increased efficient and effective collaboration amongst NERC and the Regional Entities has resulted through the centralization and appropriately secure distribution of information across Regions (including EA results, trending analysis, and lessons learned), and the increased clarity and standardization of processes provided by the software solution.

RADS. The RADS system provides for a more efficient method for NERC to complete seasonal and long-term reliability assessment reports. Specifically, RADS automates the importing of data, provides for ad hoc and pre-defined reporting, and provides access to historical data. In fact, a recent benchmarking exercise indicated that RADS enabled a routine data import process to be completed in 22 minutes as compared to prior manual work efforts totaling roughly 80 hours. This process improvement has allowed NERC's analysts and engineers to spend more time analyzing reliability and less time importing and managing data. Additional benefits of RADS include:

- **Management of Reliability Risk.** By allowing analysts to refocus their efforts on higher value work, the implementation of RADS is resulting in more and better analyses of future conditions and risks.
- **Improved Quality.** Part of the reason for the respected status of the ERO and its assessments is the high level of quality embodied within its documents. If factual errors were introduced into NERC's reliability assessments, such errors would considerably diminish the ERO's credibility. By centralizing information and reducing the number of manual interventions required to manage data, the RADS system aids in ensuring that the information contained within NERC assessments is accurate and correct.
- **Increased Security.** NERC has obligations to ensure the integrity and security of assessment data. Having a central place to manage and store assessment data has reduced the number of instances of confidential proprietary data being handled and managed at NERC. As such, the risk of accidental inappropriate disclosure has been reduced.

Document Management. As a third example, as described previously, NERC commenced implementation of a document management program during 2015 and 2016. The evaluation of the cost-benefit of the document management program indicated tremendous value to the organization, primarily in terms of addressing the business requirements set forth above. The cost benefit analysis of this project also demonstrated that NERC's projected average cost per user is comparable to market. In addition, assuming achievement of modest personnel efficiency gains (between 2-7 percent) from using the new system, the program will generate value in terms of increased resource availability well above anticipated costs. The project was reviewed in depth with the board of trustee's Standards Oversight and Technology Committee and Finance and Audit Committee, which, together with the Board, authorized reserve funding at their May, 2015 meetings to commence initiation of the program.

In all three of these examples, NERC's planning process and associated approval gates have led to thorough review of both costs and benefits of technology benefits prior to moving forward. As the planning process has matured, NERC has begun to analyze potential benefits to the Regional Entities when considering the benefits from potential IT investments. In the Enterprise Reporting – GADS business case brought before the TLT in April, NERC included estimates of productivity gain in terms of both NERC staff and the staff of the Regional Entities. NERC estimated that across the ERO Enterprise, in the first year of operation, 32 Regional Entity employees would save roughly 10 hours of time and 42 NERC employees would save roughly 29 hours of time, with benefits increasing in future years as users became more familiar with the system and as the system was expanded with additional data. This saved time represents additional value that those employees can provide by not having to manage data or duplicate work. Beyond this analysis, the business case considered less quantifiable benefits to both NERC and the Regional Entities in terms of supporting the ERO Enterprise Strategic Plan and reducing reliability risk.

As the planning process continues to develop and mature, NERC will continue to expand incorporation of regional staffing and budget impacts into its business case analysis, as well as identifying economies of scale, efficiency improvements, and enhancements to reliability through IT investment.

Resource Requirements

Personnel

The increase in Information Technology FTEs is due to the reallocation of personnel to strengthen project management oversight over NERC and ERO Enterprise software application development and implementation.

Contract and Consulting Resources to Support Internal Operations

The 2017 budgeted amounts are set forth in Exhibit C, with a comparison to 2016 budgeted amounts. The increase in the 2017 budget compared to 2016 is primarily due to the inclusion of ongoing maintenance costs for recently added ERO Enterprise applications and costs for the document management program.

2017 IT Operating Expenses

A summary of the major categories of IT Operating Expenses are set forth in the following table:

Office Costs	Budget 2016	Budget 2017	Variance
Telephone	$ 225,000	$ 230,000	$ 5,000
Telephone - Answering Service	3,000	2,500	(500)
Internet	350,000	358,920	8,920
Computer Supplies and Maintenance			
Computers	25,000	25,000	-
Computer Supplies	96,100	98,100	2,000
Maintenance & Service Agreements	1,365,295	1,706,088	340,793
Software	59,000	59,000	-
Subscription and Publications	108,300	108,300	
Dues	2,500	2,500	
Express Shipping	5,000	5,000	-
Total Office Costs	**$ 2,143,420**	**$ 2,595,408**	**$ 356,213**

Telephone Expenses
Office telephone costs are items associated with cellular phone, mobile laptop cellular air card, Session Internet Protocol (SIP) data circuits, and conference calling expenses.

Internet Expense
Internet expense is comprised of data circuits, and redundant capability in the event of primary service provider failure.

Computer Supplies and Maintenance
Computers are items that do not meet the criteria to be considered a capital expense, such as desktop computers or iPads. Computer supplies are expense items required for infrastructure support. Maintenance and service agreements comprise those items required to support internal and external access to routers, switches, firewalls, intrusion protection, file servers, audiovisual equipment, storage area networks, data backup services, network and security monitoring, co-location data center services, video conferencing, digital certificates, and development and virtualization software. Service agreements related to the co-location data center, offsite backup of data, conference calling, and network and security monitoring consume a large portion of the maintenance and service agreements budget.

Software
Tools such as Adobe Creativity Suite, remote support tools, and various other IT support tools are included under this line item. The tools are primarily used for NERC infrastructure purposes to support and manage the application, server, and network environment.

2017 IT Fixed Asset (Capital) Expenses
The following table presents a summary of NERC's IT 2017 fixed asset (capital) budget[37] compared to the 2016 budget:

IT CAPITAL BUDGET	2016	2017
ERO Application Development	$ 1,500,000	$ 700,000
Document Management	465,000	335,000
Hardware (Storage, servers, laptops)	955,000	991,000
Other Equipment	535,000	885,000
Disaster Recovery	200,000	150,000
NERC Software licenses	256,000	211,000
Total IT Capital Budget	**$ 3,911,000**	**$ 3,272,000**

As in prior years, the goal of the 2017–2019 planning period is to provide access, visibility, and analysis of data from many different sources; this will requires ongoing investments in hardware, software, and associated tools. The overarching theme is to securely gather, analyze, and maintain data across the ERO Enterprise to support ERO operations. Adding the capability to centralize and mine data—in addition to foundational elements such as the Microsoft xRM application, SharePoint 2013, and disaster recovery and enhanced security—sets the stage for vastly improved reporting and business intelligence. It also allows the capability for collaboration and sharing of information vital to the ERO's mission.

[37] NERC's total 2017 fixed asset (capital) budget is $4,372,000, and includes $1.1M budgeted in E-ISAC for portal enhancements and other costs related to CRISP.

In addition to the investments described above to support efficiency and consistency across the Enterprise, the 2017 budget also includes the cost of security enhancements, network assets, software, servers, laptops, and other hardware to support daily operations.

Human Resources

Background and Scope

Human Resources (HR) manages all of NERC's HR functions, including staffing, benefits administration, employee relations, performance and compensation management, and training and development. Management has implemented a robust, objective, and auditable performance management system to track corporate and individual performance against pre-established goals, objectives, and measures. Each year NERC continues to refine and improve this system.

Leadership, Management, and Professional and Administrative Staff Training and Development

As part of the 3-year ERO Enterprise Strategic Plan to engage and retain highly qualified talent with the leadership and technical skills to support the mission, NERC's executives, managers, and professional and support staff participate in ongoing training and development to improve competencies critical to success and succession planning for critical roles. As such, NERC will continue to invest in learning opportunities in several areas. First, HR will continue to host and optimize an e-leaning platform, SkillSoft, to provide staff resources for improving soft and technical skills. Second, HR will provide broad-based staff development training though real-world access via tours of and training on control centers, electric substations, and power generation plants. Finally, staff will have access to additional education, including but not limited to degree-oriented university education, pursuit of specialized certifications, and other in-house and external training that provides essential competencies and skills development that will lead to improved organization performance.

Compensation Consulting

Consultants are periodically retained to examine appropriate compensation based on current market data. This ensures that decisions affecting compensation are made in light of the current market climate and that qualified employees are attracted and retained within a defined total remuneration range. NERC also periodically retains compensation subject matter experts to perform periodic assessments of the BOT compensation model to ensure alignment with market practices.

Surveys

NERC periodically retains a vendor to conduct Board of Trustees and committee effectiveness surveys to identify improvement opportunities. HR will also launch additional surveys as appropriate, based on business needs, which may include periodic internal climate surveys.

Succession Planning

Minimizing disruption of knowledge, skill, and experience of key staff is critical to the company's success. HR works with senior management to identify essential roles and develop strategies to build succession and contingency plans for any loss of staff.

HR Products and Services Automation

HR will continue to operate, maintain, and investigate investment in additional electronic platforms for HR support services that reduce administrative burden and improve employee access to tools and information.

Resource Requirements

Personnel
The slight increase in FTEs is due a lower vacancy rate in 2017 compared to 2016.

Contractor Expenses
Contractor and consultant expenses are set forth in additional detail in Exhibit C. The increase over 2016 is primarily due to increased investments for additional leadership and staff training.

Miscellaneous Expenses
Miscellaneous expenses include community responsibility and employee engagement, the year-end employee appreciation event, and employee rewards and recognition.

Finance and Accounting

Background and Scope

NERC's Finance and Accounting department manages all finance and accounting functions, including employee payroll, 401(k), 457(b), and 457(f) plans, travel and expense reporting, monthly financial reporting, sales and use tax, meeting and events planning and services, insurance, internal auditing, and facilities management. This area also holds primary responsibility for the development of the annual business plan and budget, as well as NERC's proposed ERO risk management framework. Over the past several years, NERC's Finance and Accounting department implemented additional policies, procedures, and controls governing day-to-day practices including contract and personnel procurements, meetings, conference planning and travel, expense reimbursement, and back office systems and procedures. The department will continue to refine, improve and, where necessary, implement additional procedures and controls.

Resource Requirements

Personnel
The reduction in FTEs is due to a reallocation of resources to other departments in 2016.

Contractor Expenses
$457k is budgeted for outside contractor and consulting support, representing an increase compared to the 2016 budget. These costs are primarily for outside professional support for auditors to support various risk management and internal control and audit intiatives, as well as to provide finance and accounting support.

Statement of Activities and Fixed Assets Expenditures
2016 Budget & Projection, and 2017 Budget
ADMINISTRATIVE SERVICES

	2016 Budget	2016 Projection	Variance 2016 Projection v 2016 Budget Over(Under)	2017 Budget	Variance 2017 Budget v 2016 Budget Over(Under)	2017 Budget Draft 1	Variance to Prior Draft Over(Under)
Funding							
ERO Funding							
NERC Assessments	$ 561,427	$ 626,997	$ 65,570	$ 519,083	$ (42,344)	$ 952,667	$ (433,583)
Penalty Sanctions	-	-	-	-	-	-	-
Total NERC Funding	**$ 561,427**	**$ 626,997**	**$ 65,570**	**$ 519,083**	**$ (42,344)**	**$ 952,667**	**$ (433,583)**
Third-Party Funding	-	-	-	-	-	-	-
Testing Fees	-	-	-	-	-	-	-
Services & Software	-	-	-	-	-	-	-
Workshops	-	-	-	-	-	-	-
Interest	-	-	-	-	-	-	-
Miscellaneous	-	-	-	-	-	-	-
Total Funding (A)	**$ 561,427**	**$ 626,997**	**$ 65,570**	**$ 519,083**	**$ (42,344)**	**$ 952,667**	**$ (433,583)**
Expenses							
Personnel Expenses							
Salaries	$ 11,054,511	$ 11,050,223	$ (4,288)	$ 11,858,590	$ 804,078	$ 11,864,014	(5,425)
Payroll Taxes	662,269	656,558	(5,711)	669,299	7,030	687,162	(17,862)
Benefits	1,369,805	1,348,538	(21,267)	1,333,443	(36,362)	1,385,477	(52,034)
Retirement Costs	1,024,669	1,101,571	76,902	1,073,642	48,973	1,088,601	(14,959)
Total Personnel Expenses	**$ 14,111,254**	**$ 14,156,890**	**$ 45,636**	**$ 14,934,974**	**$ 823,720**	**$ 15,025,254**	**(90,280)**
Meeting Expenses							
Meetings	$ 315,000	$ 351,681	$ 36,681	$ 350,000	$ 35,000	$ 315,000	35,000
Travel	653,945	651,240	(2,705)	653,945	-	653,945	-
Conference Calls	63,300	62,110	(1,190)	19,307	(43,994)	19,307	-
Total Meeting Expenses	**$ 1,032,245**	**$ 1,065,031**	**$ 32,786**	**$ 1,023,251**	**$ (8,994)**	**$ 988,251**	**35,000**
Operating Expenses							
Consultants & Contracts	$ 3,036,671	$ 2,585,495	$ (451,176)	$ 3,359,787	$ 323,116	$ 3,199,787	160,000
Office Rent	3,054,287	2,987,777	(66,510)	3,117,009	62,722	3,117,009	-
Office Costs	2,920,678	2,713,155	(207,523)	3,275,952	355,274	3,245,952	30,000
Professional Services	2,334,300	1,961,280	(373,020)	2,293,135	(41,165)	2,293,135	-
Miscellaneous	32,000	32,000	-	32,000	-	32,000	-
Depreciation	1,920,234	1,751,253	(168,981)	1,233,650	(686,584)	1,233,650	-
Total Operating Expenses	**$ 13,298,171**	**$ 12,030,960**	**$ (1,267,210)**	**$ 13,311,534**	**$ 13,363**	**$ 13,121,534**	**$ 190,000**
Total Direct Expenses	**$ 28,441,669**	**$ 27,252,881**	**$ (1,188,788)**	**$ 29,269,759**	**$ 828,090**	**$ 29,135,039**	**$ 134,720**
Indirect Expenses	**$ (28,551,669)**	**$ (27,323,087)**	**$ 1,228,582**	**$ (29,376,484)**	**$ (824,815)**	**$ (29,257,139)**	**$ (119,345)**
Other Non-Operating Expenses	**$ 110,000**	**$ 70,206**	**$ (39,794)**	**$ 106,725**	**$ (3,275)**	**$ 122,100**	**(15,375)**
Total Expenses (B)	**$ -**	**$ 0**	**$ (0)**	**$ -**	**$ 0**	**$ -**	**$ 0**
Change in Assets	**$ 561,427**	**$ 626,997**	**$ 65,570**	**$ 519,083**	**$ (42,344)**	**$ 952,667**	**(433,583)**
Fixed Assets							
Depreciation	(1,920,234)	(1,751,253)	168,981	(1,233,650)	686,584	(1,233,650)	-
Computer & Software CapEx	2,347,000	2,749,562	402,562	1,472,000	(875,000)	1,572,000	(100,000)
Furniture & Fixtures CapEx	-	14,611	14,611	-	-	-	-
Equipment CapEx	1,464,000	365,000	(1,099,000)	1,800,000	336,000	1,800,000	-
Leasehold Improvements	-	566,361	566,361	-	-	-	-
Allocation of Fixed Assets	(1,890,766)	(1,944,281)	(53,515)	(2,038,350)	(147,584)	$ (2,138,350)	100,000
Inc(Dec) in Fixed Assets (C)	**$ -**	**$ -**	**$ (0)**	**$ -**	**$ (0)**	**$ -**	**$ 100,000**
TOTAL BUDGET (=B + C)	**$ -**	**$ 0**	**$ (0)**	**$ -**	**$ 0**	**$ -**	
FTEs	**71.23**	**73.62**	**2.39**	**69.33**	**(1.91)**	**71.36**	**(2.03)**

Section B — Supplemental Financial Information

Breakdown by Statement of Activity Sections

The following detailed schedules support the consolidated Statement of Activities. All significant variances were described by program area in the preceding pages.

Table B-1
Operating Reserve and Assessment Analysis

Operating Reserve and Assessment Analysis Statutory		Total Reserves	Future Obligations Reserve[1]	Operating Contingency Reserve	Operator Certification	CRISP	Assessment Stabilization Reserve
Beginning Working Capital and Operating Reserves Balance		**6,075,782**	**3,431,795**	**1,213,419**	**930,568**	**500,000**	
Generation or (Use) from 2016 Operations							
From 2016 budgeted operations		862,799		1,109,651	(246,852)		
From 2016 approved use of reserves		(1,117,056)	(320,218)	(796,838)			
Proceeds from financing activities (non-current portion only)		1,256,042		1,256,042			
Debt Service		(1,055,000)		(1,055,000)			
Other adjustments to reserves		1,806,132	(464,868)	-			2,271,000
Projected Working Capital and Operating Reserves - 12/31/16		**7,828,700**	**2,646,709**	**1,727,275**	**683,716**	**500,000**	**2,271,000**
Required Working Capital and Operating Reserves - 12/31/17	[2]	**7,759,102**	2,646,709	2,227,275	714,118	500,000	1,671,000
Adjustment in funding to achieve required reserve balance		530,402	-	500,000	30,402	-	
Penalty sanctions available 1-1-2017 (See Table B-2)		500,000					500,000
Less: Penalty sanction offset in 2017		(1,100,000)		-			(1,100,000)
Total Adjustments to Reserves		**(69,598)**	**-**	**500,000**	**30,402**	**-**	**(600,000)**
Assessment Reconciliation							
2017 Expenses and Capital Expenditures		69,602,175		60,018,178	1,291,557	8,292,440	
Less: Penalty sanction offset in 2017		(1,100,000)		(1,073,757)		(26,243)	
Adjustment in funding to achieve required reserve balance		530,402	-	500,000	30,402	-	
Less: Other Funding Sources		(9,195,417)	-	(882,942)	(1,321,958)	(6,990,517)	
Less: Proceeds from financing activities (non-current only)		(966,667)		(966,667)			
Plus: debt service		985,750		985,750			
2017 NERC Assessment		**59,856,243**					

[1] As further explained in the discussion of the Working Capital Reserve amount in Exhibit E, the Future Obligations Reserve offsets future, non-current liabilities. The calculation of Working Capital and Operating Reserve balances per 2015 audited financials and as projected for 2016 and 2017 is included with the Statements of Financial Position on page 91.

[2] On August 11, 2016, the NERC Board of Trustees approved the Working Capital and Operating Reserve Balance at 12/31/17.

Table B-2
Penalties

Penalty Sanctions

Until recently, penalty monies received prior to June 30 were to be used to offset assessments in the subsequent year's budget, as documented in *NERC Policy – Accounting, Financial Statement and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standard*, as well as Section 1107.2 of the Rules of Procedure. The NERC Board has approved an updated Working Capital and Operating Reserves Policy that has also been approved by FERC. This updated Policy allows NERC, with FERC approval pursuant to Section 1107.4 of the Rules of Procedure, to place penalty funds into a new Assessment Stabilization Reserve for use in future years to offset assessments. For the 2017 budget, $500,000 of penalty funds received prior to June 30, 2016 were deposited into this reserve account. NERC proposes that $1,100,000 of those funds be used to offset assessments for the 2017 budget with the remaining $1,671,000 held in the Assessment Stabilization Reserve for future assessment offsets.

All penalties received through June 30, 2016 are detailed below, including the amount and date received.

Allocation Method

Penalty sanctions used to offset 2017 assessments have been allocated to the following statutory programs to reduce assessments: Reliability Standards, Compliance Assurance, Compliance Analysis and Certification, Compliance Enforcement, Reliability Assessments and System Analysis, Performance Analysis, Training and Education, Situation Awareness, Event Analysis, and E-ISAC. Penalty sanctions are allocated based on the number of FTEs in the program divided by the aggregate total FTEs in the programs receiving the allocation. In addition to the information noted below, an additional $500,000 is expected in May 2017 related to an agreed-upon penalty settlement through WECC resulting from the September 2011 blackout.

Penalty Sanctions	Date Received	Amount Received
Penalties received between 7/1/2015 and 6/30/2016		
	May-16	$ 500,000
		$ 500,000
Penalties received prior to 6/30/2015, held in the assessment stabilization reserve		$ 2,271,000
Total penalties available to offset assessments		$ 2,771,000
Adjustments		
Penalties held in assessment stabilization reserve		(1,671,000)
Total Penalty Sanctions included in the 2017 Budget		$ 1,100,000

Table B-3
Outside Funding

Outside Funding Breakdown By Program (Excludes Penalty Sanction)	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget
Reliability Standards				
Workshops	$ 105,000	$ 105,000	$ 105,000	$ -
Interest Income Allocation	445	5,374	427	(18)
Total	$ 105,445	$ 110,374	$ 105,427	$ (18)
Compliance Analysis, Registration and Certification				
Interest Income Allocation	$ 251	$ 2,860	$ 187	$ (64)
Total	$ 251	$ 2,860	$ 187	$ (64)
Compliance Assurance				
Workshops	$ -	$ -	$ -	$ -
Interest Income Allocation	479	$ 4,710	386	(93)
Total	$ 479	$ 4,710	$ 386	$ (93)
Compliance Enforcement				
Interest Income Allocation	$ 302	$ 3,682	$ 327	$ 25
Total	$ 302	$ 3,682	$ 327	$ 25
Reliability Assessments and System Analysis				
pc_GAR Software	$ 50,000	$ -	$ 50,000	$ -
Workshops	15,000	15,000	15,000	-
Interest Income Allocation	462	3,634	351	(111)
Total	$ 65,462	$ 18,634	$ 65,351	$ (111)
Performance Analysis				
Interest Income Allocation	$ -	$ 2,554	$ 234	$ 234
Total	$ -	$ 2,554	$ 234	$ 234
Training and Education				
Testing Fees and Certificate Renewals	$ 1,267,972	$ 1,267,972	$ 1,321,900	$ 53,928
CEH Fees	600,000	600,000	600,000	-
Interest Income Allocation	183	2,096	175	(7)
Total	$ 1,868,155	$ 1,870,068	$ 1,922,075	$ 53,921
Event Analysis				
Workshops	$ 40,000	$ 78,073	$ 40,000	$ -
Interest Income Allocation	274	2,918	281	7
Total	$ 40,274	$ 80,991	$ 40,281	$ 7
Situation Awareness				
Workshops	$ -	$ 1,128	$ -	$ -
Interest Income Allocation	137	1,816	140	3
Total	$ 137	$ 2,944	$ 140	$ 3
E-ISAC				
Third Party Funding (CRISP)	$ 6,830,738	$ 7,335,757	$ 6,990,447	$ 159,709
Workshops	70,000	70,000	70,000	-
Interest Income Allocation	468	6,254	491	24
Total	$ 6,901,206	$ 7,412,011	$ 7,060,938	$ 159,732

- Operator Certification – The 2017 budget reflects prior year actual results and the anticipated number of tests to be taken in 2017.
- E-ISAC – The increase in third-party funding is due to the increase in NERC costs, which are funded equally by participants in CRISP and through assessments.

Table B-4
Personnel

Personnel Expenses	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Total Salaries	$ 28,842,336	$ 29,052,918	$ 30,073,438	$ 1,231,102	4.3%
Total Payroll Taxes	1,871,367	1,830,724	1,847,130	(24,237)	-1.3%
Total Benefits	3,579,280	3,390,190	3,643,806	64,526	1.8%
Total Retirement	2,990,823	3,015,135	3,076,956	86,134	2.9%
Total Personnel Costs	$ 37,283,807	$ 37,288,967	$ 38,641,331	$ 1,357,525	3.6%
FTEs	192.47	145.02	189.88	(2.59)	-1.3%
Cost per FTE					
Salaries	$ 149,852	$ 200,337	$ 158,381	8,529	5.7%
Payroll Taxes	9,723	12,624	9,728	5	0.1%
Benefits	18,596	23,377	19,190	594	3.2%
Retirement	15,539	20,791	16,205	666	4.3%
Total Cost per FTE	**$ 193,710**	**$ 257,130**	**$ 203,504**	**$ 9,794**	**5.1%**

- Salaries - Total Salaries expense is comprised of base salaries, incentive compensation, deferred compensation, employment agency fees and temporary office expenses. The 2017 budget for base salaries assumes a 3% increase over actual 2016 base salaries and is inclusive of market adjustments and promotions. Due to the addition of more senior staff in 2016, and the need to pay higher market-based compensation than previously budgeted to attract and retain employees, the actual average salary is higher than the 2016 budget, which causes the comparison of 2017 budget to 2016 budget to be higher than 3%. The 2017 budget for incentive compensation is based on historical actuals and is slightly higher as a percent of base salaries, 20.9% in 2017 compared to 19.5% in 2016. The 2017 budgets for deferred compensation, employment agency fees and temporary office expenses are generally consistent with 2016.
- Payroll taxes are decreasing based upon the 2016 projection and the reduction in total FTEs. While total Salaries expense is increasing, the maximum salary subject to FICA taxes limits the change in employer costs.
- Benefits are budgeted to increase based on the most recent market data as provided by NERC's insurance broker.
- There have been no changes to NERC's retirement plans. Retirement expenses are increasing at a higher rate consistent with the 3% increase in base salaries.

Table B-5
Meetings

Meetings	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Meetings	$ 1,096,500	$ 1,194,500	$ 1,071,500	$ (25,000)	-2.28%
Travel	$ 2,203,786	$ 2,190,184	$ 2,203,786	(0)	0.62%
Conference Calls	$ 320,000	$ 261,880	$ 97,600	(222,400)	-62.73%
Total Meetings	**$ 3,620,286**	**$ 3,646,564**	**$ 3,372,886**	**$ (247,400)**	**-6.83%**

- The 2017 budget for Meetings expense in the Operator Certification Program is $25.0k lower than the 2016 budget based upon prior year actual results.
- The 2017 budget for Conference Calls is $222.4k, 69.5%, lower than 2016 based upon the planned execution of a contract with a new provider scheduled to occur in 2016. This reduction in Conference Calls expenses will offset an increase in maintenance costs associated with a new audio visual lease related to new equipment and associated service and maintenance agreements.

Table B-6
Consultants and Contracts

NOTE: This table has been replaced by Exhibit C, and is further discussed in the Executive Summary on page 14

Table B-7
Rent

Office Rent	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Office Rent	$ 2,987,777	$ 2,954,287	$ 2,838,144	$ (149,633)	-5.01%
Utilities	-		-	-	
Maintenance	100,000	270,000	278,866	178,866	3.28%
Total Office Rent	**$ 3,087,777**	**$ 3,224,287**	**$ 3,117,009**	**$ 29,232**	**0.95%**

- The decrease in Office Rent is due to the termination of the lease at NERC's former Washington, DC office.
- Maintenance costs at NERC offices increase year over year per the terms of the lease agreements.

Table B-8
Office Costs

Office Costs	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Telephone	$ 548,596	$ 410,053	$ 539,737	$ (8,859)	-1.61%
Telephone Answering Srv	3,000	3,355	2,500	(500)	-16.67%
Internet	375,900	369,021	383,366	7,466	1.99%
Office Supplies	173,800	177,392	194,000	20,200	11.62%
Computer Supplies and Maintenance	-	-	-	-	
Computers	25,000	26,000	25,000	-	0.00%
Computer Supplies	98,400	85,607	101,400	3,000	3.05%
Maintenance & Service Agreements	1,875,126	1,858,992	2,426,139	551,013	29.39%
Software	117,500	226,643	122,500	5,000	4.26%
Network Supplies	-	-	-	-	
Publications & Subscriptions	167,650	190,852	180,460	12,810	7.64%
Dues	48,050	63,165	49,316	1,266	2.64%
Postage	16,350	15,786	16,221	(129)	-0.79%
Express Shipping	28,200	17,405	28,216	16	0.06%
Copying	105,000	104,993	110,123	5,123	4.88%
Reports	2,000	1,362	362	(1,638)	-81.90%
Stationary/Forms	2,500	1,090	2,500	-	0.00%
Equipment Repair/Service Contracts	75,000	75,000	75,000	-	0.00%
Bank Charges	42,500	26,494	25,000	(17,500)	-41.18%
Sales & Use Taxes	5,000	500	-	(5,000)	-100.00%
Merchant Card Fees	86,000	86,575	77,500	(8,500)	-9.88%
Total Office Costs	**$ 3,583,328**	**$ 3,740,288**	**$ 4,359,340**	**$ 563,768**	**21.66%**

- The increase in Office Supplies is primarily related to increased needs at NERC's Washington, D.C. office.
- The increase in Maintenance and Service agreement costs related to:
  - New in software audit tool in Compliance Assurance, $100k
  - New software analytic tools used in RASA, $37k
  - Increase in maintenance costs for new data center hardware installed in 2015 and 2016, and new network storage devices, $200k
  - Increase in maintenance costs for new audio visual equipment planned for 2016, $164k

Table B-9
Professional Services

Professional Services	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Independent Trustee Fees	$ 1,126,354	$ 1,126,354	$ 1,226,000	$ 99,646	8.85%
Trustee Search Fee	100,000	100,000	100,000	-	0.00%
Outside Legal	690,000	590,000	515,000	(175,000)	-25.36%
Lobbying	50,000	50,000	60,000	10,000	20.00%
Accounting & Auditing Fees	154,500	154,500	159,135	4,635	3.00%
Insurance Commercial	225,000	225,000	230,000	5,000	2.22%
Outside Services	163,446	168,446	178,000	14,554	8.90%
Total Services	**$ 2,509,300**	**$ 2,414,300**	**$ 2,468,135**	**$ (41,165)**	**-1.64%**

- The increase in Independent Trustee Fees was approved by the Board of Trustees on August 13, 2015. Independent Trustee Fees are included in the Professional Services budget in the General and Administrative and Executive department.
- The reduction in outside legal fees, budgeted in the Legal and Regulatory department, is based on bringing more work in-house and a reduction in projected outside legal needs due to the completion of certain contract negotiations.
- The increase in Lobbying expense, budgeted in the Legal and Regulatory department, is based upon prior year actual expenses. This expense is primarily related to NERC's monitoring of regulatory and legislative issues and responding to information requests related to these activities.
- The increase in outside service costs is primarily due to various employee benefit management systems budgeted in the Human Resources department.

Table B-10
Miscellaneous

Miscellaneous Expenses	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Miscellaneous Expense	$ 6,500	$ 6,500	$ 6,500	$ -	0.0%
Employee Rewards and Recognition	10,000	$ 10,000	10,000	-	0.0%
Community Resp & Employee Engagement	10,000	10,000	5,000	(5,000)	-50.0%
Year-end Employee Recognition Event	10,000	10,000	15,500	5,500	55.0%
Total Miscellaneous Expenses	**$ 36,500**	**$ 36,500**	**$ 37,000**	**$ 500**	**1.4%**

The total 2017 Miscellaneous Expenses budget shows a minor increase of $500 over the 2016 budget.

This budget is intended to cover the cost of:

1. Token gifts to retiring employees, condolence flowers in the event of a death in the family of an employee, and similar types of miscellaneous expenses ($6.5k);
2. Funds to support Community Responsibility and Employee Engagement Committee activities ($5.0k);
3. Departmental and company team-building activities and employee rewards and recognition expenses that are not otherwise included in personnel expenses ($10.0k); and
4. Year-end employee recognition meal expenses ($15.50k). $5.0k was reallocated from Community Responsibility and Employee Engagement expenses to the Year-End Employee Recognition Event to better align the budget with prior year actual results.

The budget for item (1) is spread throughout all Programs and Administrative departments. The budget for items (2) and (4) are included in the Human Resources department. The budget for item (3) was split equally between General and Administrative and Human Resources in the 2016 Budget, but is budgeted in Human Resources only in 2017.

Table B-11
Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Property Tax Expense	$ 50,000	50,000	$ 50,000	-	
Interest Expense	60,000	60,000	56,725	(3,275)	-5.46%
Total Other Non-Operating Expenses	**$ 110,000**	**$ 110,000**	**$ 106,725**	**$ (3,275)**	**-2.98%**

Budgeted interest expense is calculated based on expected draws on the capital financing loan. Refer to Exhibit D, page 125 for more detailed information related to debt repayment and the interest expense calculation.

Table B-12
Fixed Assets

Fixed Assets	Budget 2016	Projection 2016	Budget 2017	Variance 2017 Budget v 2016 Budget	Variance %
Depreciation	$ (2,641,943)	$ (2,558,606)	$ (1,691,457)	$ 950,486	-35.98%
Computer & Software CapEx	2,447,000	2,362,402	2,572,000	125,000	5.11%
Furniture & Fixtures CapEx	-	-	-	-	
Equipment CapEx	1,464,000	1,545,797	1,800,000	336,000	22.95%
Leasehold Improvements	-	-	-	-	
	$ 1,269,057	**$ 1,349,593**	**$ 2,680,543**	**$ 1,411,486**	**111.22%**

As further explained in the Executive Summary on page 15 and in Section A in the Information Technology section on page 77 and the E-ISAC section on page 61, expenditures for fixed assets, excluding the reversal of Depreciation expense, are budgeted to be $461.0k higher in 2017 compared to 2017. The increase in Computer & Software CapEx is primarily due to the combination of lower costs resulting from a delay in the potential replacement for the current compliance monitoring and enforcement tracking tool, originally planned for 2017, and the increase in costs related to the portal enhancement project. This delay in the compliance monitoring and enforcement tracking tool resulted in a $800k decrease in ERO applications development from $1.5M in 2016 to $700k in 2017. The increase in Equipment CapEx is primarily for security devices.

Table B-13
2018-2019 Projections
NOTE: Refer to the Executive Summary beginning on page 21

Section C — Non-Statutory Activity

NERC has no non-statutory activities.

Section D — Supplemental Financial Statements

NORTH AMERICAN ELECTRIC RELIABILITY COPORATION

STATEMENT OF FINANCIAL POSITION

	12/31/2015 Per Audit	12/31/2016 - Projection	12/31/2017 - Projection
ASSETS			
Cash	40,308,955	39,464,020	39,091,525
Trade Accounts receivable, net of allowance for uncollectible accounts of $0 and $62,573 in 2013 and 2012	3,986,346	3,986,346	3,986,346
Prepaid expenses and other current assets	1,291,805	1,291,805	1,291,805
Security deposit	125,416	125,416	125,416
Plan Assets - 457b	744,439	744,439	744,439
Plan Assets - 457f	271,200	271,200	271,200
Property and equipment	8,301,730	9,411,545	12,669,171
Total Assets	**55,029,891**	**55,294,771**	**58,179,902**
LIABILITIES AND NET ASSETS			
Liabilities			
Current Portion			
Accounts payable and accrued expenses (incl, vacation accrual)	5,326,723	5,326,723	5,326,723
Accrued Incentive Comp	4,721,278	4,956,779	4,872,492
Deferred rent-current	322,016	400,434	480,457
Deferred compensation-current	-	-	-
Capital lease obligations - current	64,728	64,728	64,728
Accrued retirement liabilities	1,878,830	1,695,570	1,761,502
Debt Service - Current Portion	744,253	857,725	650,231
Deferred income	7,961,316	7,961,316	7,961,316
Deferred revenue - penalties	-	-	-
Deferred revenue - CRISP	2,508,514	2,508,514	2,508,514
Regional assessments	12,273,666	12,273,666	12,273,666
Total Current Portion	**35,801,324**	**36,045,455**	**35,899,629**
Long-Term Portion			
Deferred compensation[1]	1,038,350	1,038,350	1,038,350
Capital Project Financing - non-current	680,311	1,011,839	1,033,333
Deferred rent - non-current	3,412,298	3,011,864	2,531,407
CRISP Insurance Reserve	500,000	500,000	500,000
Deferred Revenue - Assessment Stabilization Reserve	-	2,271,000	2,271,000
Capital lease obligations - non-current	151,752	151,752	151,752
Total Non-Current Portion	**5,782,711**	**7,984,805**	**7,525,842**
Total Liabilities	**41,584,035**	**44,030,260**	**43,425,472**
Net Assets - unrestricted	9,735,856	10,764,511	14,254,430
Net Assets - restricted	3,710,000	500,000	500,000
Total Liabilities and Net Assets	**55,029,891**	**55,294,771**	**58,179,902**

[1]Includes 457b liability, life insurance for former executive, and retiree medical

NORTH AMERICAN ELECTRIC RELIABILITY COPRORATION

Statement of Activities, Fixed Asset Expenditures and Change in Working Capital by Program	Statutory Total	Statutory Activities: Reliability Standards	Compliance Analysis, Registration & Certification	Compliance Assurance	Compliance Enforcement	Reliability Assessment and System Analysis	Performance Analysis	Operator Certification	Training and Continuing Education	Event Analysis	Situation Awareness	E-ISAC	General and Administrative (Includes Executive and Gov't Relations)	Legal and Regulatory	Information Technology	Human Resources	Accounting and Finance
Funding																	
ERO Funding																	
NERC Assessments	59,856,314	7,835,213	3,576,122	7,713,879	5,677,854	7,339,030	4,821,146		1,822,089	5,300,955	3,980,236	11,270,705	519,083	-	-	-	-
Penalty Sanctions	1,100,000	159,642	69,980	144,334	122,465	131,213	87,475		43,738	104,970	52,485	183,698			-		
Total NERC Funding	**60,956,314**	**7,994,855**	**3,646,102**	**7,858,213**	**5,800,319**	**7,470,243**	**4,908,621**		**1,865,827**	**5,405,926**	**4,032,721**	**11,454,403**	**519,083**	-	-	-	-
Third-Party Funding (CRISP)	6,990,447											6,990,447					
Testing Fees	1,921,900							1,321,900	600,000								
Services & Software	50,000					50,000											
Workshops	230,000	105,000				15,000				40,000		70,000					
Interest	3,000	427	187	386	327	351	234	58	117	281	140	491					
Miscellaneous	-																
Total Funding (A)	**70,151,660**	**8,100,282**	**3,646,289**	**7,858,599**	**5,800,647**	**7,535,594**	**4,908,855**	**1,321,958**	**2,465,944**	**5,446,206**	**4,032,862**	**18,515,341**	**519,083**	-	-	-	-
Expenses																	
Personnel Expenses																	
Salaries	30,073,438	2,340,405	1,125,154	2,509,618	1,790,859	2,247,826	1,349,579	245,337	606,753	1,708,049	873,869	3,417,398	3,476,241	2,148,056	3,261,320	770,439	2,202,533
Payroll Taxes	1,847,130	151,658	76,383	163,335	117,205	142,919	92,093	18,342	44,385	108,739	58,749	204,023	173,245	119,055	216,747	28,144	132,107
Benefits	3,643,806	307,085	174,014	333,557	184,106	263,230	143,104	84,920	54,319	212,232	156,328	397,467	396,300	151,930	389,091	72,977	323,144
Retirement Costs	3,076,956	259,407	126,651	276,273	198,694	246,609	149,018	30,026	67,599	189,397	96,159	363,482	197,650	232,244	359,376	46,242	238,131
Total Personnel Expenses	38,641,331	3,058,556	1,502,203	3,282,783	2,290,865	2,900,585	1,733,794	378,625	773,056	2,218,416	1,185,105	4,382,370	4,243,437	2,651,285	4,226,534	917,802	2,895,916
Meeting Expenses																	
Meetings	1,071,500	207,000	4,000	60,000	2,500	74,000	1,000	30,000	25,000	81,500	6,500	230,000	334,000	4,000	7,500	2,000	2,500
Travel	2,203,786	271,988	155,146	276,343	56,736	208,338	118,172	7,389	13,751	152,487	33,005	256,488	444,515	93,231	56,508	8,728	50,963
Conference Calls	97,600	40,565	610	6,100	366	5,270	2,965	153	10,980	4,270	305	6,710	5,856	1,952	9,608	305	1,586
Total Meeting Expenses	3,372,886	519,553	159,756	342,443	59,602	287,608	122,137	37,541	49,731	238,257	39,810	493,198	784,371	99,183	73,616	11,033	55,049
Operating Expenses																	
Consultants & Contracts	13,127,749			50,000		525,000	528,082	219,800	360,800		1,295,850	6,788,429	15,000		2,312,787	575,000	457,000
Office Rent	3,117,009												3,117,009				
Office Costs	4,359,340	51,336	24,231	141,198	20,379	147,652	74,843	43,216	57,107	49,634	41,897	431,895	507,934	46,411	2,595,408	11,748	114,450
Professional Services	2,468,135											175,000	1,431,000	495,000		63,000	304,135
Miscellaneous	37,000	500	500	500	500	500	500		500	500	500	500	500	500	500	30,000	500
Depreciation	1,691,457	231,721				125,621			1,919	85,582	7,667	5,297	438,305		795,345		
Total Operating Expenses	24,800,690	283,556	24,731	191,698	20,879	798,773	603,426	263,016	420,326	135,715	1,345,914	7,401,121	5,509,749	541,911	5,704,041	679,748	876,085
Total Direct Expenses	**66,814,907**	**3,861,666**	**1,686,689**	**3,816,924**	**2,371,347**	**3,986,965**	**2,459,356**	**679,182**	**1,243,113**	**2,592,388**	**2,570,828**	**12,276,689**	**10,537,557**	**3,292,379**	**10,004,191**	**1,608,583**	**3,827,050**
Indirect Expenses	0	4,180,279	1,832,451	3,779,431	3,206,790	3,435,846	2,290,564	572,641	1,145,282	2,748,677	1,374,338	4,810,185	(10,644,282)	(3,292,379)	(10,004,191)	(1,608,583)	(3,827,050)
Other Non-Operating Expenses	**106,725**	-	-	-	-	-	-	-	-	-	-	-	106,725				
Total Expenses (B)	**66,921,632**	**8,041,945**	**3,519,141**	**7,596,355**	**5,578,137**	**7,422,812**	**4,749,920**	**1,251,823**	**2,388,395**	**5,341,065**	**3,945,167**	**17,086,873**	-	-	-	-	-
Change in Assets	**3,230,028**	**58,337**	**127,149**	**262,244**	**222,510**	**112,782**	**158,936**	**70,136**	**77,549**	**105,141**	**87,695**	**1,428,467**	**519,083**	-	-	-	-
Fixed Assets																	
Depreciation	(1,691,457)	(231,721)	-	-	-	(125,621)	-	-	(1,919)	(85,582)	(7,667)	(5,297)	(438,305)	-	(795,345)	-	-
Computer & Software CapEx	2,572,000											1,100,000			1,472,000		
Furniture & Fixtures CapEx	-																
Equipment CapEx	1,800,000														1,800,000		
Leasehold Improvements	-																
Allocation of Fixed Assets	0	290,058	127,149	262,244	222,510	238,403	158,936	39,734	79,468	190,723	95,361	333,765	438,305	-	(2,476,655)	-	-
Inc(Dec) in Fixed Assets (C)	**2,680,543**	**58,337**	**127,149**	**262,244**	**222,510**	**112,782**	**158,936**	**39,734**	**77,549**	**105,141**	**87,695**	**1,428,467**	-	-	-	-	-
TOTAL BUDGET (=B + C)	**69,602,175**	**8,100,282**	**3,646,289**	**7,858,599**	**5,800,647**	**7,535,594**	**4,908,855**	**1,291,557**	**2,465,944**	**5,446,206**	**4,032,862**	**18,515,341**	-	-	-	-	-
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**549,485**	**(0)**	-	-	-	**(0)**	**0**	**30,402**	-	-	**(0)**	**0**	**519,083**	-	-	-	-
FTEs	**189.88**	**17.16**	**7.52**	**15.51**	**13.16**	**14.10**	**9.40**	**2.35**	**4.70**	**11.28**	**5.64**	**19.74**	**16.92**	**11.28**	**23.27**	**2.82**	**15.04**

Exhibit A – Common Assumptions

Shared Business Plan and Budget Assumptions NERC and the Regional Entities 2016–2019 Planning Period (2017 Budget Cycle)

NERC and the eight Regional Entities are committed to a common operating model[38] that describes the characteristics of a highly effective and efficient electric reliability organization (ERO) Enterprise. This operating model includes action items to address coordinated strategic and business planning as well as performance monitoring processes across the enterprise. These processes remain transparent, with results reported out on a quarterly basis to NERC's Corporate Governance and Human Resources Committee and NERC Board of Trustees (Board) in support of the ERO corporate oversight function.

Recently, at its November 2015 meeting, the Board approved an updated version of the ERO Enterprise Strategic Plan with goals, objectives, and deliverables for the 2016–2019 planning period. The strategic plan lays out five goals that the ERO Enterprise will focus on over the next three years. They include (1) standards; (2) compliance, enforcement, registration, and certification; (3) risks to reliability; (4) emerging risks; and (5) coordination and collaboration. The plan also identifies a number of associated objectives and deliverables to achieve the goals of the ERO Enterprise. There are also four overarching performance metrics to assess the overall effectiveness of the ERO Enterprise in addressing risk to the Bulk Electric System (BES) and improving BES reliability in 2016. These metrics concentrate on (1) measuring progress in achieving reliability results, (2) assuring standards and compliance effectiveness, (3) improving risk mitigation, and (4) program execution.

The following set of common assumptions has been developed to guide ERO Enterprise resource projections[39] for the 2016–2019 period. Specifically, it supports the strategies heading into the 2016 year and establishes common assumptions, goals and objectives as the ERO Enterprise begins the 2017 Business Plan and Budget (BP&B) cycle. Additionally, it outlines how these goals and objectives set the stage for periods beyond 2017, all in support of achievement of the goals and objectives set forth in the Strategic Plan.

Similar to prior planning cycles, the specific resource needs and budgets of NERC and the Regional Entities will be publicly posted and made available on NERC's website for review. Each Regional Entity board approves its BP&Bs after an extensive review process that includes consideration of stakeholder input. Also, the BP&Bs of NERC and each Regional Entity are approved in open session by NERC's Finance and Audit Committee and Board of Trustees as part of the annual BP&B process. NERC's review of the Regional Entity BP&Bs will be primarily focused on ensuring alignment of activities with the Strategic Plan and adequacy of resources to support performance of delegated functions and key efforts. A 2017 BP&B schedule has been developed to identify important meeting dates, review periods, posting dates, etc. associated with the development and completion of the NERC and Regional Entity BP&Bs.

These assumptions will continue to be refined based on comments received from stakeholders and the ongoing work conducted by NERC and Regional Entity leadership regarding specific goals, objectives, and supporting activities over the planning period.

[38] ERO Enterprise Operating Model

[39] NERC recognizes there are often unique factors that drive differences in each entity or organization's final determination of its resource needs and budget. Regional Entity-specific assumptions are stated in each Regional Entity's BP&B as appropriate.

Legal and Operating Framework

NERC and the Regional Entities will continue to work under the existing regulatory framework governing the establishment and enforcement of reliability standards for the BES established by applicable governmental authorities in the United States, provincial regulatory and/or governmental authorities in Canada, and portions of Mexico, as well as the authorizations contained in the Federal Energy Regulatory Commission's (FERC) Order approving NERC as the ERO.

NERC continues to enhance its oversight of the Regional Entities' performance of their delegated functions. NERC in collaboration with the Regional Entities will continue to develop goals, measures, and reports to assess and evaluate the Regional Entities' performance of their Regional Delegation Agreements (RDAs), NERC's Rules of Procedure, the Compliance Monitoring and Enforcement Program, FERC requirements, and directives that are in effect pursuant to Section 8(c) of the RDAs. NERC will continue to provide feedback and direction to the Regional Entities on performance improvements. NERC and the Regional Entities will also continue to work collaboratively to refine and revise processes and procedures to eliminate duplication, increase operational efficiencies, enhance ERO-wide consistency, and achieve measureable reliability outcomes. Regional Entities will continue to have the primary responsibility for day-to-day operations and interactions with registered entities.

Stakeholder Participation

NERC and the Regional Entities develop their BP&B's based upon the assumption of continued stakeholder participation in support of key program areas, while recognizing that stakeholder resource limitations may affect specific levels of participation in any given activity. The availability and adequacy of industry resource support will be evaluated on an ongoing basis.

External Factors

The performance and execution of BP&B's for each entity in the ERO Enterprise may be impacted by various external factors. These factors include, but are not limited to, the following:

- FERC Orders, other applicable governmental authority actions, directives, audits, mitigation efforts, and performance assessments;
- Environmental Protection Agency (EPA) rules that could potentially impact the reliability and/or operation of the BES;
- Other governmental agencies or departments that may issue rules, guidelines, orders, or directives that may impact the operation of the BES;
- The number and significance of changes within Balancing Authorities' and Reliability Coordinators' areas, prompting the need for associated re-certification and reliability plan assessments;
- The unanticipated rise in the rate and severity of entity violations;
- The unanticipated rise in the rate and severity of system events requiring formal investigations beyond historic volumes, and causal drivers of these events;
- New technologies and changes in resource or demand composition that require additional reliability studies and reliability risk analysis, including new techniques for conducting relevant assessments;
- Changes in applicable laws and regulations, including environmental laws and others;
- Priority risk activities identified by the Reliability Issues Steering Committee, committees of the Board, and through other stakeholder input;

- The ability of stakeholders to support the pace and scope of the various activities while implementing the results of earlier efforts.

Collaboration with the Trade Associations and Forums

The activities of the North American Transmission Forum (NATF), North American Generator Forum (NAGF), and other trade forums and associations are expected to complement ERO Enterprise activities and mitigate incremental resource needs of NERC and Regional Entities in certain areas. NERC has a memorandum of understanding with the NATF and NAGF to help ensure that the common objectives of each organization are achieved in the most efficient and effective manner. Increased collaboration between the NERC and the NATF and NAGF is expected to continue.

Key Assumptions by Program Area[40]

Reliability Standards Program

- It is expected the number of continent-wide standards development projects will remain relatively stable, except as required to address any new FERC directives to create or modify reliability standards, or industry submittals of standard authorization requests.
- Continent-wide standards projects will consist primarily of conducting enhanced periodic reviews on existing standards to improve their content and quality, respond to identified risks to reliability (including those that may be identified through the implementation of risk-based Compliance Monitoring and Enforcement), and address FERC directives that may arise. This activity will require the allocation of technical resources from several internal NERC departments (e.g., Reliability Assessment and Performance Analysis (RAPA), Reliability Risk Management (RRM), Compliance Analysis and Certification, and Compliance Assurance) and support from across the ERO Enterprise.
- During the enhanced periodic review of ERO standards, any associated regional standards will be reviewed for potential incorporation as variances or as improvements to the continent-wide requirements. Regional and NERC standards development processes may require modification to accomplish efficiently this task. Each Regional Entity will work with NERC and possibly other Regional Entities on projects where there is a regional standard/variance. Regional standards development activity will be driven by requests the Regional Entity may receive or reliability issues the Regional Entity may identify. Regional standards development activity is expected to remain low.
- In coordination with Standard Drafting Teams and consistent with current approaches, Regional Entities may support outreach during standard development, and participate in the standard development activities as may be required to address reliability and stakeholder issues that may arise within their respective regions. Additionally, following FERC approval, NERC and the Regional Entities collectively will assist the transition of standards to compliance monitoring and enforcement by providing knowledge that supports industry and auditor training, or providing information regarding the intent of the standard.
- The number of interpretations are expected to remain low. However, guidance requests associated with the implementation of Standards may increase.

Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs

[40] These statements, which are generally organized by program area, are intended to help guide resource allocation decision-making in the development of the 2017 BP&Bs.

Compliance and Enforcement

- The implementation of the risk-based compliance monitoring and enforcement program (CMEP) will continue to require the allocation of dedicated resources from both NERC and the Regional Entities for both compliance and enforcement. Regional Entities created a plan in 2016 to complete Inherent Risk Assessments (IRAs) for all their Reliability Coordinators, Balancing Authorities, and Transmission Operators and will require resources to complete the remaining IRAs in 2017. In addition, Regional Entities will require resources to update previously done IRAs based on identified triggers, and focus on creating compliance oversight plans that include compliance monitoring tools, the frequency of compliance monitoring, and the standards that are to be monitored as well as the depth of testing of those standards.
- NERC and the Regional Entities will continue the 2015-2016 ERO Enterprise exercises to evaluate business practices, implementation, and consistency within risk-based compliance monitoring.
- NERC and the Regional Entities will participate in ERO Enterprise consistency activities, including providing input into standards development.
- NERC and the Regional Entities are planning to support the training and education requirements and guidelines necessary to meet the criteria set forth by the *ERO Enterprise Compliance Monitoring and Enforcement Manual* and the *Competency Guide*.
- The suitability of software systems currently used for compliance, registration, analysis and tracking will continue to be evaluated from a strategic perspective, which may result in changing or replacing existing systems in the future. However, until such changes have been identified, reviewed and approved by the ERO Enterprise Technology Leadership Team and EROEMG for implementation, NERC and the Regional Entities should continue to maintain the necessary resources to support existing systems.
- Planning and operating standard violations are expected to level off or continue decreasing as most registered entities have been audited and thus have a greater understanding of compliance expectations, and the standards have matured.
- Compliance personnel will need to continue to support the implementation of cyber-security reliability standards version 5 (CIP V5):
    - NERC will lead the CIP V5 training development, coordination, and facilitation for the ERO Enterprise CIP auditors and industry outreach. ERO Enterprise CIP auditors will support these activities in collaboration with NERC to ensure appropriate knowledge and guidance is developed, understood by industry, and administered.
    - The allocation of resources in 2017 and 2018 should be responsive to continued implementation by registered entities of new versions of the CIP Standards, while recognizing that the risk-informed focus will be on monitoring “high” and “medium” impact requirements.
- Additional resource allocation may be necessary for increased Physical Security compliance monitoring activities for CIP-014.
- ERO Enterprise CMEP staff, particularly staff with visibility into risks occurring in the field, will provide feedback to the ERO Enterprise. This feedback may include information on risks seen in the field that are not addressed by a standard as well as information on where a standard is too broad. ERO Enterprise CMEP staff will participate in the development of a solution, regardless of whether the solution is a standard or other solution.

- ERO Enterprise CMEP staff will provide input for standards development teams on the risks seen in the field relating to a standard under development, as well as how a standard would be monitored.

Organization Registration and Certification

- Two central reforms have been identified as a result of the completion of the risk-based registration activity in 2015:

  1. Modifications to the NERC Registry Criteria have been approved, including the elimination of three functional entities (Purchasing-Selling Entities, Interchange Authorities, and Load-Serving Entities), modifications to the threshold criteria for Distribution Providers, and alignment of five registration categories with the BES definition.

  2. The NERC-led panel, which establishes subset lists of applicable reliability standards for registered entity functions (e.g., Under-Frequency Load Shedding-only Distribution Providers), has been incorporated into the rules.

These reforms strengthen the registration process and are important milestones in NERC's approach to managing risks to reliability. Deployment and implementation of these revisions began in 2015, with continued work in 2016 and possibly 2017.

- No further enhancements are anticipated to support the ongoing next phases of the risk-based registration activity.
- Based on the 2015 technical assessment of the Phase 2 registered functions (Transmission Operator, Transmission Owner, Generator Owner, and Generator Operator), development of subsets of standards are not necessary.
- The certification and registration programs will be assessed in 2016, which may result in modifications to the program in 2017.
- The activities associated with the implementation of the BES definition have decreased, therefore no additional resource demands are expected in the registration area.
- Planned oversight activities for 2017 will be aligned with the ERO Enterprise Operating Model and should not affect 2017 resource allocation and should have little effect on overall NERC resource requirements. NERC understands that each Regional Entity will need to evaluate its individual resource needs and allocations.

Reliability Assessment and Performance Analysis Program (RAPA)

- Support and leadership to (1) the Planning Committee and (2) standing committees' subcommittees, working groups, and task forces serving the standing committees will continue.
- NERC and the Regional Entities will continue to focus resources on high quality reliability assessments and performance analysis, including:
  - Development and implementation of expanded and enhanced enterprise-based data collection and analysis systems, and capabilities for performance analyses. This includes TADS, GADS, NERC RAS data, and misoperations data;
  - Support of the integration of RAPA information systems for assessments and associated data requirements, with focus on objective and technically sound reliability assessments supporting delivery of high quality reports (e.g., long-term, short-term, special or scenario assessments, and State of Reliability Report);

  - Development of assessment and performance analysis techniques as well as resource capabilities and tools, including probabilistic and scenario evaluations, which address the reliability impacts of new technologies, changing resource or demand resource composition, and environmental related regulations or legislation;
  - Providing technical resources and expertise to perform analyses as needed, including to support and identify risk priorities for standards development, compliance, and enforcement activities;
  - Development of appropriately tailored analysis and overall assessment, including guidance for registered entities, of high impact, low frequency BES risks, including physical security and geomagnetic disturbance (GMD) vulnerability.
  - Providing technical resources to support up to four short-term reliability assessments (6-18 month horizon replacing the current summer and winter assessments), which focus on specific reliability risk areas and geographic areas with specific reliability concerns, while also allowing for regional assessments;
  - Support of the common approach developed for NERC reliability assessments to ensure consistent treatment of resource and reliability evaluations.

- NERC and the Regional Entities will advance analytical capabilities for identifying and determining reliability risks and conducting various reliability assessments by:
  - Integrating the analysis and measures of essential reliability services (ERS) into the Long-Term Reliability Assessment. The process encompasses new data collection and analysis approaches needed to address assessment objectives of identifying reliability issues due to a changing resource mix;
  - Requiring advanced powerflow and stability analysis tools and objective expert input for transmission/deliverability assessments and studies;
  - Maturing and developing interconnection-wide analysis groups to support the assessment of interconnection-wide risks, such as frequency response;
  - Providing technical resources and reliability leadership for the advancement of probabilistic analyses supporting the Long-Term Reliability Assessment;
  - Requiring advanced statistical analysis tools and objective expert input to support them for probabilistic assessments.

- NERC will support the maintenance of the BESnet application and manage processing of the Regional BES Exception Requests (ERs), including technical validation of the definition and exception requests, self-determined notification submittals, periodic reviews of network changes affecting BES determinations, as well as requests for registration and certification reviews. The Regional Entities will continue to process BES ERs per guidelines established in the NERC Rules of Procedure.[41]

- NERC and Regional Entities' resources (through the case building designee agreements) will support the Planning Coordinators' development of long-term sustainable interconnection-wide powerflow and dynamics model cases under reliability standards MOD-032 and MOD-033 that exhibit the accuracy and fidelity reflecting actual BES reliability performance and dynamic conditions. These models will integrate needed elements that address reliability behavior of changing resource mix and technology of both generation and loads, including:

[41] NERC Rules of Procedure

  - Development of a process to ensure the continued compilation and creation of annual sets of seasonal and future steady state and dynamic simulation model cases;
  - Provision of technical resources to support the effective and continuous improvement of the models that incorporate recognition of reliability behavior of loads and generation associated with the changing resource mix;

- NERC and the Regional Entities will work collaboratively to enhance the ERO Enterprise's capability for post event analysis, including:
  - Development of a process to ensure the compilation and creation of steady state and dynamic simulation model cases for use in the investigation and analysis of major power system disturbance events;
  - Development and tracking of metrics that demonstrate the accuracy of the powerflow and dynamics models to replicate actual system conditions and reliability behavior;
  - Evaluation of event disturbances using phasor measurements and other methods to assess sufficiency of data and models.
- NERC and the Regional Entities may require contractor and consultant services to maintain continued support and technical expertise associated with activities listed in the above assumptions and with supporting special assessment, scenario, or other technical research efforts. It could potentially impact both NERC and Regional Entity resource allocation:
  - If significant events occur, contractor services may be required to support wide-area system analyses and root cause evaluations.
  - Contractor services may be necessary to support special assessment analyses (e.g., EPA 111(d) evaluation or ERS), scenario analyses (e.g., polar vortex-like severe event analyses and gas-electric interdependence), and other technical research efforts (e.g., similar to geomagnetic disturbances, and FAC-003 Vegetation Management).

Training, Education, and Operator Certification Program

- NERC will continue to budget for the unified learning management system (LMS) focused initially on Regional Entity audit staff, with near-term consideration for risk-based compliance monitoring and enforcement related staff. Future inclusion of other ERO functional areas is expected as potential requirements present themselves during system development. NERC will work with the Regional Entities to consolidate training resources and promote better coordination, planning, delivery and management of training and outreach efforts across the enterprise without adversely impacting Region-specific training requirements.
- The implementation of CMEP staff training and competencies are expected to influence the allocation of training resources throughout the enterprise. NERC will continue the development of compliance training modules with assistance of qualified subject matter experts from the Regional Entities and incorporation of outside expertise/services.
- An allocation of additional resources may be required to support certain training and outreach activities of the risk-based CMEP:
  - Regional Entities should allocate resources to meet the requirements for the compliance and enforcement staff that are associated with the implementation of the risk-based CMEP.
- The Regional Entities, in collaboration with NERC, are expected to help assess and determine training and outreach needs. This includes flexibility in approach between Regional Entities, and

anticipating areas of support for their staff and stakeholders for standards, compliance monitoring and enforcement, situation awareness and event analysis, and information technology. Addressing these needs will likely require additional resource allocation and budgeting considerations.

- NERC, in collaboration with Regional Entities, will develop and deliver additional CIP V5 training to support the transition. This may require consideration for additional funding of the NERC training and education budget.
- The Operating Personnel Certification program is expected to remain at a steady state with no additional resources required from the Regional Entities.
- Contractor and consultant services may be necessary to maintain the continued support and technical expertise associated with some enterprise training, outreach and education activities.

Situation Awareness and Infrastructure Security (including Events Analysis)

- NERC will continue to provide required support and leadership for the Operating Committee and the Critical Infrastructure Protection Committee, and standing committees, subcommittees, working groups, and task forces serving the standing committees. Regional Entity involvement is expected to remain at current levels with no additional resources required from the Regional Entities.
- Registered Entity participation in the ERO Event Analysis Process, which involves active participation by Regional Entity staffs, will continue at or above current levels through 2016.
- NERC will continue to budget and incur costs to operate and maintain the software application known as Situational Awareness for FERC, NERC, and Regional Entities, Version 2 (SAFNRv2) for situation awareness, and The Event Analysis Management System (TEAMS) for Events Analysis. The allocation of additional resource investments are expected to maintain the capabilities of SAFNRv2 throughout the planning period. Any such investments will be NERC funded and not result in an allocation of cost to the Regional Entities.
- Regional Entities will continue to budget for event analysis and situational awareness activities based on their respective Region's historical workload, as they did in the past. Some Regional Entities will continue to allocate resources as part of the activities accounted for under their RAPA program, and should clearly delineate where the activities' resources are budgeted.
- Regional Entities will support critical infrastructure security activities in the context of situation awareness, using those designated resources, unless specifically budgeted and managed elsewhere.

Electricity Information Sharing and Analysis Center (E-ISAC)

- NERC will continue to fund, operate and maintain the E-ISAC, with no increased cost to the Regional Entities.
- NERC will continue to fund and conduct the Grid Security Exercise program, with no increased cost to the Regional Entities. Analysis and planning activities will occur during even-numbered years and execution of the exercise will take place in odd-numbered years.
- NERC will continue to fund and conduct the Grid Security Conference as an annual event. Other than funding registration fees for individual attendees from their Regional Entity, no Regional Entity funding is anticipated.

Information Technology and Project Management Office (PMO)

- NERC and the Regional Entities will work collaboratively to refine existing strategies and governance and procurement practices applicable to the development, operation, and maintenance of enterprise architecture, including software and data systems supporting both NERC and Regional Entity operations.
- NERC's BP&B will include ongoing funding support for the development, operation, and maintenance of ERO Executive Management Group (EMG)-approved enterprise applications. Enterprise application funding in any given year will be subject to the budget and funding limits set forth in NERC's approved BP&B. Regional Entities should include appropriate funding for applications and supporting systems designed to satisfy Regional business needs (if not within the mutually agreed upon scope of the ERO Enterprise applications that are funded by NERC).
- Regional Entities may be required to provide or augment business teams to help develop application business requirements and to test business functionality within the ERO applications.
- Ongoing investments will be required to develop, implement, and maintain enhancements to the NERC and Regional Entity websites, ERO applications, and ERO data repositories, which are required to improve access to information and data. NERC and the Regional Entities will separately fund any enhancements to their own websites.

ERO Enterprise-wide Risk Management

- A common ERO Enterprise risk management framework commenced in 2014 to focus on identifying, assessing, prioritizing, and mitigating risks associated with the performance of both NERC and the Regional Entities. This will be a multi-year activity with the project expected to reach steady state by 2017.
- NERC's Director of Risk Management and Internal Audit is responsible for the overall development of this framework, with the approval of the ERO Regional Executives and under the oversight of NERC's Enterprise Wide Risk Management Committee.
  NERC and the Regional Entities will continue to devote resources to implement this framework. Activities include validating and prioritizing risks for EROEMG review and approval. The results will serve as an input into the NERC's future audit plans, which are reviewed and approved by the NERC Board of Trustees Enterprise Risk Management Committee. Regional Entities may add risk management and internal control resources as needed.

Exhibit B – Application of NERC Section 215 Criteria

DISCUSSION OF HOW THE NERC MAJOR ACTIVITIES IN THE 2017 BUSINESS PLAN AND BUDGET MEET THE NERC WRITTEN CRITERIA FOR DETERMINING WHETHER A RELIABILITY ACTIVITY IS ELIGIBLE TO BE FUNDED UNDER FEDERAL POWER ACT SECTION 215

Introduction

This Exhibit discusses how the major activities in NERC's 2017 Business Plan and Budget meet the NERC written criteria for determining whether a reliability activity is eligible to be funded under §215 of the Federal Power Act ("FPA §215"). This Exhibit is intended to satisfy Recommendation No. 38 resulting from the financial performance of NERC conducted by the Commission's Division of Audits ("DA") in 2012-2013 and adopted by the Commission in its November 2, 2012 order on NERC's 2013 Business Plan and Budget.[1] NERC submitted the written criteria to the Commission in a compliance filing dated February 21, 2013 in Docket No. FA11-21-000.[2] The Commission approved the NERC written criteria, with modifications, in an order issued in that docket on April 18, 2013.[3] The NERC written criteria as used in this Exhibit incorporate the modifications specified in the Compliance Order.[4]

II. Reliability Standards Program 2017 Major Activities

The major activities of the Reliability Standards Program are described at pages 24-26 of the 2017 Business Plan and Budget. The Reliability Standards Program carries out the ERO's responsibility to develop, adopt, obtain approval of, and modify as and when appropriate, mandatory Reliability Standards for the reliable planning, operation, and critical infrastructure protection of the North American BES. The major activity areas for this program include (1) providing project management and leadership to the reliability standard development process to deliver high-quality, continent-wide reliability standards, both new and modified, including standard development outreach activities, facilitation of Standard Drafting Team activities, drafting support, assisting Standard Drafting Teams in adhering to the processes in the *Standard Processes Manual*, and ensuring that the quality of documents produced are appropriate for approval by industry and the NERC Board; (2) facilitating continent-wide industry engagement in the standard development processes; and (3) conducting industry balloting on standards, disseminating information on standards and the standard development processes, and supporting regulatory filings and proceedings relating to standards. Additionally, the Reliability Standards Program provides technical advice and final quality review for Regional Entity standards development processes, presents proposed regional standards to the

[1] *North American Electric Reliability Corporation, Order Accepting 2013 Business Plan and Budget of the North American Electric Reliability Corporation and Ordering Compliance Filing*, 141 FERC ¶ 61,086 (2012) ("2013 Budget Order"). Recommendation 38, as adopted in the 2013 Budget Order, is: "In its annual business plan and budget filings, [NERC should] provide an explanation as to why the proposed activities to be undertaken by each program area for the budget year are statutory, including, at a minimum: a description and the purpose of the major activities to be taken by each program area and an explanation for why the activity is a statutory activity." *Id.* at P 16.

[2] *Compliance Filing of the North American Electric Reliability Corporation in Response to Paragraph 30 of November 2, 2012 Commission Order – NERC Written Criteria for Determining Whether a Reliability Activity is Eligible to be Funded Under Federal Power Act Section 215*, filed February 1, 2013 in Docket No. FA 11-21-000 ("February 1, 2013 Compliance Filing").

[3] *North American Electric Reliability Corporation, Order on Compliance*, 143 FERC ¶ 61,052 (2013) ("Compliance Order").

[4] For ease of reference, the complete NERC written criteria, as modified in accordance with the Compliance Order, are provided at the end of this Exhibit.

NERC Board, and prepares submissions for approval of regional standards to the applicable regulatory authorities in the U.S. and Canada.

For 2017, the major activities of the Reliability Standards Program will focus on (1) selection of standards projects to be undertaken based on the nature of the reliability issue, cost compared to risks, and whether a standard or another solution is most appropriate to address the issue; (2) addressing Commission directives and responding to Commission orders as necessary through the standards process; (3) performing enhanced periodic reviews of standards; and (4) facilitating smooth transitions to new standards through developing guidelines, webinars, and other activities to support auditor and industry training for new standards. Identification of need for new standards projects will be based on sources such as Commission directives and reliability risks identified by the Reliability Risk Management Process or the Reliability Issues Steering Committee (RISC).

The major activities of the Reliability Standards Program satisfy the following criteria:

I.A: Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure (ROP)?

I.B: Is the activity necessary or appropriate for providing guidance and assistance to Regional Entities in carrying out Regional Reliability Standards development activities?

I.C: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated?

I.D: Is the activity necessary or appropriate for the provision of training and education concerning Reliability Standards development processes, procedures, and topics for/to (i) NERC personnel, (ii) Regional Entity personnel, (iii) industry personnel?

II.F.1: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (ii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as (1) Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents.

IV: Is the activity one that was required or directed by a Commission order issued pursuant to §215? (Reliability Standards development projects re often initiated in response to directives in Commission orders).

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §300 and Appendix 3A.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18

C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

X. Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

III. Compliance Monitoring and Enforcement and Organization Registration and Certification Program Area 2017 Major Activities

The major activities of the Compliance Monitoring and Enforcement and Organization Registration and Certification Program Area are described at pages 28-30, 31-33, and 35-41 of the 2017 Business Plan and Budget. This Program Area is comprised of three operational groups: (1) Compliance Assurance (addressing compliance monitoring), (2) Reliability Assurance (addressing assurance, organization registration and certification), and (3) Compliance Enforcement.

The Compliance Assurance group works collaboratively with the Regional Entities to ensure effective implementation of risk-based compliance monitoring under the Compliance Monitoring and Enforcement Program ("CMEP") across the entire ERO Enterprise. This group's activities include the following major activities and functions: (1) ensuring that Regional Entities monitor registered entities for compliance according to their specific facts and circumstances, developing customized compliance oversight plans (COPs) for each registered entity based on its inherent risk assessment (IRA); (2) overseeing Regional Entities' IRAs of registered entities; (3) oversight of the quality implementation of the risk-based compliance monitoring program; (4) development of the annual CMEP Implementation Plan; (5) oversight of use of necessary compliance-related processes, procedures, IT platforms, tools and templates; (6) development and delivery of education and training for ERO Enterprise staff; (7) conducting CIP V5 training and education programs and other outreach that support industry compliance and integration of risk assessment and internal controls; (8) coordinating with the NERC Standards department for standards development to provide compliance information, statistics, and perspectives to standard drafting teams to foster development of standards that provide increased reliability benefit and clarify compliance risks, and to assist in smooth transitions for standards from development to enforceability, including by providing draft compliance monitoring guidance, information on how compliance with draft standards will be determined, and input on auditability and enforceability; (9) supporting Regional Entity and industry committees, working groups and task forces, such as the NERC Compliance and Certification Committee; (10) industry training for every Reliability Standard approved by the Commission, as well as industry-focused outreach events and webinars on risk-based CMEP activities; and (11) promoting registered entities' development of effective compliance programs and internal controls.

The ongoing and new major activities of the Compliance Assurance group for 2017 will include: (1) continuing to mature the risk-based compliance program, including fully developing customized COPs for registered entities; (2) working with NERC Enforcement and IT and with Regional Entity staffs on improvements in the existing compliance reporting, analysis, tracking system and other compliance tools supporting risk-based activities; (3) supporting successful implementation of CIP V5 standards and subsequent enhancements that become effective in 2017 and beyond; (4) continuing to monitor and

support effective implementation and monitoring of the Physical Security Reliability Standard; (5) initiating a training program to support implementation of common audit procedures for each standard; and (6) continuing to integrate standards and compliance functions for clear stakeholder implementation, including through a common set of Reliability Standards Audit Worksheets, measures, or successors for all standards and in initiating a compliance phase-in learning period for all standards.

The Compliance Analysis, Certification and Registration group is responsible for a range of requirements and activities embodied in Section 500 and Appendices 5A and 5B of the NERC ROP, including providing technical resource support to standards development, compliance monitoring, and enforcement; ensuring that all entities impacting the BES are registered commensurate with risk; ensuring all Reliability Coordinators ("RC"), Balancing Authorities ("BA") and Transmission Operators ("TOP") are certified; conducting industry reliability assurance activities; and ensuring that compliance gaps identified in reportable events are assessed and addressed if appropriate. Major activities of this group include (1) registration of BES users, owners, and operators who are responsible for compliance with Commission-approved Reliability Standards; (2) evaluating and certification of the competency of RCs, BAs and TOPs; (3) conducting activities to reasonably assure the ERO that certain actions have been taken as reported in response to NERC Alerts or guidance to industry; (4) providing oversight of Regional Entity implementation of regional registration, compliance, certification, investigation, and complaint programs and processes; (5) conducting investigations of identify Possible Violations of Reliability Standards in response to complaints, BES disturbances, or other triggers, including participating on all Regional Entity-led investigations and observing as requested on Commission-led reliability investigations and inquiries; and (6) working with Regional Entity staff to confirm that qualified events and disturbances are evaluated against the relevant Reliability Standards and to ensure formal compliance monitoring occurs if indicated. Specific major activities of Compliance Analysis, Certification and Registration for 2017 will include continuing to work with the NERC-led panel to review registered entities for deregistration or applicability to a reduced number of Reliability Standards; and implementing registration program improvements and certification program improvements identified in 2016, including conducting training as necessary.

The Compliance Enforcement department is responsible for overseeing enforcement processes, the application of penalties or sanctions, and activities to mitigate and prevent recurrence of noncompliance with Reliability Standards. The Department works collaboratively with the Regional Entities to ensure consistent and effective implementation of the risk-based CMEP, including evaluating the consistency of disposition methods including assessment of penalties or sanctions. It also focuses on ensuring that the ERO Enterprise dedicates resources to the matters that pose the greatest risk to reliability. The Compliance Enforcement department monitors Regional Entities' enforcement processes and provides oversight over the outcomes of such processes, to ensure due process, identify best practices and process efficiency opportunities, and promote consistency among Regional Entities' business practices; collects and analyzes compliance enforcement data and trends to assist with identification of emerging risks and help to inform development of enforcement policy and processes; files notices of penalty ("NOP") and other submittals associated with noncompliance discovered through Regional Entity compliance, monitoring and enforcement activities; processes and files NOPs and other submittals discovered through NERC-led investigations and audits; collaborates with other NERC departments, including Compliance Assurance, Reliability Standards and Regional Entity Coordination; and delivers training of the ERO Enterprise staff and outreach to registered entities on compliance and enforcement topics. Compliance Enforcement also conducts outreach activities that focus on self-logging, compliance exceptions, risk elements, CIP V5, IRAs, and internal controls.

During 2017, the Compliance Enforcement department will continue to focus on the successful implementation of, as well as refining and improving, the risk-based CMEP. The major activities of Compliance Enforcement will include refining and improving risk-based CMEP processes; implementing in a transparent manner the risk-focused ERO Enterprise enforcement philosophy; expanding the feedback loop of information from Enforcement to Standards and other program areas; and working with Compliance Assurance, IT, and Regional Entity staff regarding improvements in the existing compliance, reporting, analysis system and other compliance tools to support risk-based activities.

The major activities of the Compliance Monitoring and Enforcement and Organization Registration and Certification Program Area satisfy the following criteria:

I.A: Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure?

I.C: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

II.B: Is the activity necessary or appropriate for the Certification of Reliability Coordinators, Transmission Operators and Balancing Authorities as having the requisite personnel, qualifications and facilities and equipment needed to perform these reliability functions in accordance with the applicable Requirements of Reliability Standards?

II.D: Is the activity necessary or appropriate for conducting, participating in or overseeing compliance monitoring and enforcement activities pursuant to the NERC ROP and (through the Regional Entities) the Commission-approved delegation agreements?

II.E: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information to monitor and enforce compliance with Reliability Standards, including evaluating the effectiveness of current compliance monitoring and enforcement processes, the need for new or revised compliance monitoring and enforcement processes, and the need for new or different means of training and education on compliance with Reliability Standards.

II.F: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as: (1) Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents. (2) Compliance monitoring and enforcement processes, including how to conduct them, how to participate in them, and the expectations for the process? This includes development of guidance documents. (3) Disseminating, through workshops, webinars,

Advisories/Recommendations/Essential Actions, and other publications, "lessons learned" information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities, monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities? (4) Registered Entity internal processes for compliance with Reliability Standards, such as development, implementation and maintenance of internal reliability compliance programs?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §400 and 500 and Appendices 4B, 4C, 5A, 5B and 5C.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX: Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in the activities encompassed by one or more of the other criteria?

X: Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

IV. Reliability Assessment and System Analysis Program 2017 Major Activities

The major activities of the Reliability Assessment and System Analysis (RASA) Program are described at pages 43-47 of the 2017 Business Plan and Budget. The RASA Program carries out the ERO's responsibility to conduct assessments of the reliability and adequacy of the BES to provide insight and guidance about reliability risks and performance improvements. RASA focuses on developing a technical framework and understanding of the reliability risks facing the industry. The principal activity areas of the RASA Program include: independent assessments and reports on the overall reliability, adequacy, and associated reliability risks that could impact the upcoming summer and winter seasons and the long-term (e.g. 10-year) planning horizon; development of focused reliability assessments based on emerging reliability risks and other reliability issues garnering an in-depth analysis; performance analysis and recommendations of historical reliability and associated trends, relying on data integrity and consistent methodology, supporting credible recommendations and guidance; reliability assessment and interconnection-wide analysis for analyzing steady-state and dynamic conditions, including frequency, Essential Reliability Services, and stability aspects; support for development and improvement of long-term sustainable interconnection-based power flow, dynamic and load models, and technical studies and practices to use these models; advancement of industry and the ERO's understanding of power system characteristics and behaviors by gathering larger PMU datasets of data for advanced data analytics and modeling improvements; reliability risk program management for identifying and improving key risk areas using analyses of reliability gaps, risks, controls, and management efforts, as well as integration with the RISC, Long-Term Reliability Assessment, short-term (seasonal) assessments, and State of Reliability reports; management of reliability risk program priorities to align with the Strategic Plan and business

plan and budget for appropriate level of resources, timing, completion and execution; and establishing reliability leadership and consistent, technically sound guidance and recommendations that position industry and policy-makers to enhance reliability through effective outreach and communications.

The RASA Program works with industry leaders to create a reliability strategy that is relevant, timely, and effective at addressing the most important reliability risks, through understanding key information identified through analysis and assessment efforts; extracting and prioritizing the associated reliability risks from that information; sharing and integrating risk analysis insights across the ERO Enterprise; and translating that knowledge into actionable guidance and recommendations for NERC management, the Board, and entities, and government policy makers. Reliability assessments evaluate the expected reliability behavior of the BPS through extensive deterministic and probabilistic analyses to identify potential reliability conditions that could compromise reliability. RASA both assesses and reports on the reliability, adequacy and associated risks that could impact short-term and long-term study periods, and conducts special reliability assessments and identifies recommendations and guidance actions that may be warranted to lessen identified risks or enhance overall reliability. RASA also coordinates forecast reliability data between planning areas, the Regional Entities, and government organizations, and produces the Electricity Supply and Demand data base. A significant ongoing effort involving RASA, Regional Entity staff, and stakeholders focuses on continued development of effective Essential Reliability Services, leading to defined Essential Reliability Services, an evaluation of initial metrics and data compilation of actual performance, and ongoing assessment.

RASA works closely with other organizations such as the Electric Power Research Institute (EPRI), Department of Energy (DOE), Institute of Electrical and Electronics Engineers (IEEE), Institute of Nuclear Power Operations (INPO), North American Transmission Forum (NATF), North American Generation Forum (NAGF), Canadian Electricity Association (CEA), Interstate Natural Gas Association of America, and Natural Gas Supply Association, on a number of energy industry reliability issues such as geomagnetic disturbances, vegetation management, variable generation integration, and interdependency of gas and electric systems.

The ongoing and new major activities of the RASA Program for 2017 include: (1) Issuing assessment reliability reports, guidelines, recommendations and alerts as needed (including verification and validation of data and information through Regional Entities and technical committees); preparing the long-term (10-year) and short-term (2 to 4 seasonal or shoulder period analyses) reliability assessments; conducting special assessments addressing key reliability risks, including potential environmental regulation impacts to BPS reliability and Essential Reliability Services issues (frequency response and controls, natural gas availability and pipeline outage assessment, and nuclear plant retirements); and preparing an annual State of Reliability Report; (2) Preparing a frequency response analysis report (to the Commission and to support Reliability Standard BAL-003 and the annual Interconnection Frequency Reporting obligations (IFRO)); meeting regulatory requirements per BAL-003-1 and other analyses and studies of frequency response. (3) Supporting a risk registry and systematic prioritization process consistent with the RISC framework and supporting BES risk profile measurements and assessment of standards. (4) Executing integrated risk control strategies and plans across the ERO Enterprise to address the highest-priority existing or emerging risks to BES reliability, and explicitly measure the results. (5) Supporting Reliability Standards development and responses to Commission directives by providing technical and system analysis expertise. (6) Supporting the technical foundation development for Reliability Standards to address deficiencies or needs identified by RASA. (7) Advancing NERC's analytical capability for identifying reliability risks and conducting various reliability assessments, including by integrating Essential Reliability Services analysis and measures into long-term reliability

assessment, proving advanced power flow and stability analysis tools for transmission/deliverability assessments and studies, and providing advanced statistical tools for probabilistic assessments. (8) Providing support and leadership to the NERC Planning Committee and to standing committees and subcommittees, working groups, and task forces. (9) Assisting in the development of approaches to registration and providing input (based on reliability trends, risks, and historical performance information) to NERC staff in support of the development CMEP risk elements, to ensure that the compliance focus remains on the most critical entities and associated Reliability Standards. (10) Supporting major event investigations, analyses, and reporting of major findings, recommendations, and lessons learned that will improve reliability. (11) Building and sustaining an ERO Enterprise Reliability Assessment and Performance Analysis team that encompasses risk-informed approaches and structured methods to identify and address reliability risks. (12) Implementing effective oversight and tracking of various technical aspects of reliability, including frequency response performance, application of TPL footnote b adoption, and root cause applications, to assessments and analyses. (13) Supporting interconnection-wide model-building groups by providing feedback on model quality and fidelity. (14) Developing a Reliability Guideline on Power Plan Model Verification, including providing industry support with webinars and training, supporting the user group in the NERC Synchronized Measurement Subcommittee, and developing a structured approach to evaluate and improve system models, model validation, system analysis, and assessments. (15) Expanding use of synchrophasor technology for power plant model verification, compliance with MOD-026/-027 standards, and internal system and model analysis. (16) Broadening understanding of inter-area, local, and forced oscillations in all interconnections, and using wide-area synchrophasor data to provide industry with better understanding of phenomena, available tools, and findings. (17) Driving education of dynamic load modeling and development of improved load models, and supporting compliance with Reliability Standard TPL-001-4, including through a Reliability Guideline on Load Comparison, Technical Reference Document on Load Modeling, a workshop on Dynamic Load Modeling and FIDVR, driving next generation dynamic load models for all software platforms, model benchmarking and testing for more robust tools and models, and developing default data sets and testing with industry to ensure robust starting points. (18) Proactively seeking to address deficiencies in interconnection-wide models used by Transmission Planners and TOPs. (19) Ensuring models can sufficiently recreate plant behavior, through exploring known/historical events and required modeling improvements to accurately represent pre- and post-events. (20) Working with interconnection model designees to positively impact case quality and robustness for industry's benefit. (21) Supporting study and policy development related to end-use load behavior, and advocate for grid-friendly load response.

During 2017, RASA will continue to work with the Regional Entities on implementation of the BES definition and processing BES Exception Requests, through reviews, evaluations, and confirmations of proposed changes to BES elements by registered entities and use of the BESnet tool.

The major activities of the RASA Program satisfy the following criteria:

I.A: is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure?

I.C.1: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (1) Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and

analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

III.A: Is the activity necessary or appropriate for the preparation or dissemination of long-term, seasonal, and special assessments of the reliability and adequacy of the Bulk Power System?

III.B: Is the activity necessary or appropriate for measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

IV: Is the activity one that was required or directed by a Commission order issued pursuant to §215? (FERC orders directed NERC to develop and implement a revised definition of "Bulk Electric System" and a procedure for requesting and receiving exceptions from the BES definition, and subsequently approved NERC's proposed revised BES definition and its proposed BES exception procedure.)

V. Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for this major activity are §801-806 and 809-810 and Appendix 5C.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX: Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

X: Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

V. Performance Analysis 2017 Major Activities

The major activities of the Performance Analysis (PA) group are described at pages 49-51 of the 2017 Business Plan and Budget. The PA group carries out the ERO's responsibility to conduct analyses of

the reliability and adequacy of the BES, which are used to provide insight and guidance about reliability risks, performance improvements, and reliability performance issues and areas of concern, including with respect to system, equipment, entity and organizational performance that may indicate a need to develop remediation strategies, action plans, or data used to revise or retire Reliability Standards or consider new Reliability Standards. PA focuses on developing a technical framework and understanding reliability risks facing the industry.

PA collects transmission outage, generator performance, demand response, and protection and control systems misoperations data in a common format using various industry databases; this data is used to develop and report grid metrics that analyze outage frequency, duration, causes, and other factors related to transmission and generator performance and automatic power system protection and control effectiveness. Trends, findings and recommendations from PA serve as technical input to Reliability Standards and to standards project prioritization, compliance process improvements, event analyses, reliability assessment, and critical infrastructure protection efforts. In 2017, PA will add wind generator data to the data collected. The analyses and results collected and produced are reported in the annual State of Reliability Report, which in 2017 will begin to reflect post-seasonal reliability review, insights from analysis of transmission, generator, and demand response data systems, and integration of event analysis and misoperations. PA also supports the NERC System Protection & Controls Subcommittee.

PA works closely with other organizations including EPI, DOE, IEEE, INPO, NATF, NAGF, and CEA, on a number of fronts, including the Transmission Availability Data System (TADS), Generator Data Availability System (GADS), and Demand Response Availability Data System (DADS).

PA's ongoing and new major activities for 2017 will include the following: (1) Issuing reliability assessment reports, guidelines, recommendations, and alerts as needed, including verification and validation of data and information through Regional Entities and technical committees, through the annual State of Reliability Report and a frequency response analysis. (2) Overseeing TADS, GADS and TADS as well as reliability metrics and protection and control systems misoperations data, including strengthening data collection and validation processes by designing, creating, testing and implementing data-checking systems for reliability assessment, system analysis and risk analysis, and providing periodic updates on trends and measures of BES reliability. (3) Serving as the business lead and working with IT, as necessary, to have in place the required tool for GADS Wind data. (4) Supporting Reliability Standards development and responses to Commission directives by providing technical and analytical expertise. (6) Assisting in the development of approaches to registration and providing input (based on reliability trends, risks, and historical performance information) to NERC staff in support of development of CMEP risk elements and ensure that the compliance focus remains on the most critical entities and associated Reliability Standards. (7) Conducting major event investigations, analyses, and reporting of major findings, recommendations, and lessons learned that will improve reliability.

The major activities of PA satisfy the following criteria:

I.A: is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure?

I.C.1: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (1)

Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks? (2) Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences and near miss events?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

III.A: Is the activity necessary or appropriate for the preparation or dissemination of long-term, seasonal, and special assessments of the reliability and adequacy of the Bulk Power System?

III.B: Is the activity necessary or appropriate for measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

V. Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for this major activity are §801-811 and Appendix 8.)

IX: Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

VI. Reliability Risk Management (Situation Awareness and Event Analysis) 2017 Major Activities

The major activities of the Reliability Risk Management ("RRM") group, which is comprised of the Situation Awareness Department and the Event Analysis Department, are described at pages 53-55and 57-58 of the 2017 Business Plan and Budget. The RRM group carries out the ERO's responsibility to perform assessments (including real-time and near-real-time continual awareness, detailed analysis of significant events, and longer-term broad performance assessments) of the reliability and adequacy of the BES, including identifying potential issues of concern relating to system, equipment, entity, and human performance. RRM has six primary functions: (1) BES awareness, (2) event analysis and determination of root and contributing causes, (3) assessment of human performance challenges that affect BES reliability and identification of improvement opportunities, (4) continent-wide analysis and reporting of BES performance, (5) support of the NERC Operating Committee, and (6) support of the NERC Critical Infrastructure Protection Committee. Through awareness and continuous assessment, RRM identifies potential reliability risks to the BES, analyzes events in detail, ensures that industry is well informed of system events, emerging trends, risk analysis, and lessons learned, and provides data and analysis to inform other aspects of NERC's statutory functions.

The Situation Awareness department along, with the Regional Entities, monitors BES conditions, significant occurrences and emerging risks, and threats across the 14 Reliability Coordinator regions in North America. Situation Awareness also supports development and publication of NERC Alerts and awareness products, and facilitates information sharing among industry, Regions and government during crisis situations and major system disturbances. Situation Awareness is engaged in enhancement, replacement, streamlining or modification of several reliability-related situation awareness and monitoring tools, including SAFNRv2, operation and maintenance pending replacement of the current secure alert tool, and retirement of the NERCnet – Interconnection Security Network and initiation of service using a new communication network developed, sponsored and managed by the Eastern Interconnection Data Sharing Network consortium. The Situation Awareness Department uses the following reliability-related tools to support its activities: Resource Adequacy (ACE Frequency) Tool; Inadvertent Interchange; Frequency Monitoring and Analysis Tool; Intelligent Alarms Tool; and Genscape (PowerIQ and PowerRT tools).

The ongoing and new major activities of the Situation Awareness department for 2017 include: ensuring that the ERO is aware of all BES events above a threshold of impact; enabling the sharing of information and data to facilitate wide area situational awareness; during crisis situations, facilitating the exchange of information among industry, Regions, and U.S. and Canadian governments; keeping the industry informed of emerging reliability threats and risks to the BES, including any expected actions; conducting the annual NERC Monitoring and Situational Awareness Conference and Human Performance Conference; and administering the NERC Alerts process as specified in §810 of the Rules of Procedure to issue Advisory (Level 1) Alerts on significant and emerging reliability and security related topics, and facilitate the tracking of actions specified in Recommendation (Level 2) and Essential Action (Level 3) Alerts.

The Event Analysis department performs assessments of the reliability and adequacy of the BES to identify potential issues of concern related to system, equipment, entity, and human performance that may indicate a need to develop remediation strategies, action plans, or data used to revise Reliability Standards or consider new Reliability Standards. Event Analysis conducts analyses to determine the causes of events, promptly assures tracking of corrective actions to prevent recurrence, and provides lessons learned to the industry. Event Analysis analyzes all reportable events for sequence of events, root cause, risks to reliability, and mitigation and ensures that the industry is well-informed of system events, emerging trends, risk analysis, lessons learned, and expected actions. Event Analysis conducts in-depth analyses of approximately 150 events per year on average. Additionally, Event Analysis identifies human error risks and precursor factors that allow human error to affect BES reliability, and educates industry regarding such risks, precursors, and related mitigation methods. Event analysis also supports compliance and standards training initiatives and trending and analysis to identify emerging reliability risks to the BES. Event Analysis works in collaboration with and supports the activities of other groups involved in human performance analysis including the NERC Operating Committee's Event Analysis Subcommittee, the WECC Human Performance Working Group, and others. Event Analysis also collaborates with industry groups including the NATF, NAGF, and trade associations.

The ongoing and new major activities for 2017 for the Event Analysis department include: (1) Working with Regional Entities to obtain and review information from registered entities on qualifying events and disturbances in order to advance awareness of events above a threshold level; facilitating analysis of root and contributing causes, risks to reliability, wide area assessments and remediation efforts; and disseminating information regarding events in a timely manner. (2) Ensuring that all

reportable events are analyzed for sequence of events, root cause, risk to reliability, and mitigation. (3) Continuing to refine risk-based methodologies to support better identification of reliability risks, including use of more sophisticated cause codes for analysis. (4) Ensuring consistency in reporting and analysis to support wide area assessments of significant reliability trends and risks. (5) Conducting training (webinars, workshops and conference support) to inform industry and the ERO of lessons learned, root cause analysis, trends, human performance, and cold weather preparedness and recommendations. (6) Developing reliability recommendations and alerts as needed. (7) Tracking industry accountability for critical reliability recommendations. (8) Ensuring that industry is well informed of system events, emerging trends, risk analysis, lessons learned, and expected actions. (9) Conducting major event analysis and reporting of major findings and recommendations that will improve reliability. (10) Advancing the quality and usefulness of reliability assessments and event analysis data. The Event Analysis department will also support several top priority reliability risk projects being led by the PA program.

The major activities of the RRM group satisfy the following criteria:

I.C.2: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (2) Monitoring, event analysis and investigations of Bulk Power System major events, off-normal occurrences and near-miss events?

II.E.2: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information to monitor and enforce compliance with Reliability Standards, including evaluating the effectiveness of current compliance monitoring and enforcement processes, the need for new or revised compliance monitoring and enforcement processes, and the need for new or different means of training and education on compliance with Reliability Standards, such as: (2) Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences, and near miss events?

II.F.3: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as: (3) Disseminating, through workshops, webinars, Advisories, Recommendations, Essential Actions, and other publications; “lessons learned” information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities; monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities?

II.G: Is the activity necessary or appropriate for the development and provision of tools and services that are useful for the provision of adequate reliability, because they relate specifically to compliance with existing Reliability Standards and they proactively help avert Reliability Standard violations and Bulk Power System disturbances?

III.C: Is the activity necessary or appropriate for investigating, analyzing, evaluating, and disseminating information concerning, the causes of major events and off-normal occurrences, and/or providing coordination assistance, technical expertise and other assistance to users,

owners, and operators of the Bulk Power System in connection with Bulk Power System major events and off-normal occurrences, but not real-time operational control of the Bulk Power System?

III.D: Is the activity necessary or appropriate for awareness of circumstances on the Bulk Power System and to contribute to understanding risks to reliability?

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §807, 808, 810 and 1001 and Appendix 8.)

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

VII. Electricity Information Sharing and Analysis Center 2017 Major Activities

The major activities of the Electricity Information Sharing and Analysis Center ("E-ISAC") are described at pages **Error! Bookmark not defined.**-63 of the 2017 Business Plan and Budget. The primary function of E-ISAC is to reduce cyber and physical risk to the Electricity Subsector across North America by providing unique insights, leadership and coordination, and to be the trusted, timely, actionable resource of grid risk information and analysis to enhance electric reliability. The E-ISAC facilitates sector coordination regarding physical security and cybersecurity events affecting the BES. E-ISAC analytic personnel maintain a detailed understanding of emerging vulnerabilities and threats within the broad industrial control systems community and the more focused BES community. E-ISAC manages and executes NERC's responsibilities in the Cybersecurity Risk Information Sharing Program ("CRISP") and acts as the program manager for CRISP. The purpose of CRISP is to facilitate the sharing of cyber threat information and to develop situation awareness tools that enhance the electricity sector's ability to identify, prioritize, and coordinate protection of its critical infrastructure. Finally, ES-ISAC also supports an annual grid security conference and a biennial Grid Security Exercise.

The major activities of the ES-ISAC satisfy the following criteria:

I.C.1: Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as: (1) Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks? (2) Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences and near-miss events?

III.D: Is the activity necessary or appropriate for awareness of circumstances on the Bulk Power System and to contribute to understanding risks to reliability.

III.E: Is the activity necessary or appropriate for gathering, analyzing and sharing with and among industry and government participants, information regarding the physical or cyber security of the Bulk Power System.

III.F: Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provisions for these major activities are §810 and 1003.)

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

VIII. Training, Education, and Operator Certification Program 2017 Major Activities

The major activities of the Training, Education, and Operator Certification Program are described at pages 65-68 of the 2017 Business Plan and Budget. The major activities of this program include oversight and coordination of the delivery of training programs to NERC and Regional Entity staff; as well as training and education for industry participants on the requirements of Reliability Standards, the Reliability Standards development process, and the compliance monitoring and enforcement process. The Training and Education Program supports the ERO's responsibilities to develop, adopt, and obtain approval of Reliability Standards and to monitor, enforce and achieve compliance with the mandatory standards. The Training and Education Program also supports NERC's System Operator Certification Program, which ensure that personnel operating the BES have the skills, training and qualifications needed to operate the BES reliably. This Program maintains the credentials required to work in system control centers across North America for over 6,000 system operators. The Training and Education Program prepares operators for complying with requirements of Reliability Standards and appropriately operating the BES during normal and emergency operations. Education and training activities include the following subject matter: risk-based compliance monitoring and enforcement; standards and compliance; registration and certification; event analysis, cause analysis, and lessons learned; reliability assessment and system analysis; continuing education for system operators; and new system operator certification examinations for the Reliability Coordinator, Transmission Operator, Balancing and Interchange Operator, and Balancing, Interchange and Transmission Operator credentials.

The major activities of the Training, Education, and Operator Certification Program for 2017 include providing and expanding training and education for ERO personnel and industry in the following areas: Reliability Standards compliance, emerging cyber-related issues; auditor skills and consistent audit and investigation techniques and standards compliance reviews, including risk-based compliance monitoring and enforcement and other improvements in compliance and enforcement practices; development and implementation of clear and technically sound Reliability Standards; lessons learned and trends from events, and identified themes from trending and common cause analysis; effective root,

apparent and common cause analysis methods; quality improvement of registered entity self-reporting and self-certification; entity registration processes, issues and alternatives; human performance fundamentals; and developing and incorporating a systematic approach to ongoing training. The Training, Education, and Operator Certification Program will continue to work with industry stakeholders and the System Operator Certification exam vendor to create certification exams that will promote reliability of the BPS. Further, the Continuing Education (CE) program will evaluate and revise the current program criteria as reflected in the CE program manual, taking into account the growth and maturation of industry training programs as well as ongoing research on adult learning to ensure the CE program continues to foster improvements in training and promotes quality in training programs.

The major activities of the Training, Education, and Operator Certification Program satisfy the following criteria:

I.D: Is the activity necessary or appropriate for the provision of training and education concerning Reliability Standards development processes, procedures and topics for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel?

II.C: Is the activity necessary or appropriate for the Certification of system operating personnel as qualified to carry out the duties and responsibilities of their positions in accordance with the Requirements of applicable Reliability Standards?

II.F: Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as: (1) Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents. (2) Compliance monitoring and enforcement processes, including how to conduct them, how to participate in them, and the expectations for the processes? This includes development of guidance documents. (3) Disseminating, through workshops, webinars, Advisories/Recommendations/Essential Actions, and other publications, "lessons learned" information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities, monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities. (4) Registered Entity internal processes for compliance with Reliability Standards, such as development, implementation and maintenance of internal reliability compliance programs?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provision for these major activities are §600 and 900.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

IX. Administrative Services 2017 Major Activities

NERC's Administrative Services Departments are Technical Committees and Member Forums (for which no funding for activities is budgeted for 2017), General and Administrative, Legal and Regulatory, Information Technology ("IT"), Human Resources, and Finance and Accounting. The major activities of these departments are described at pages 69-79 of the 2017 Business Plan and Budget.

General and Administrative includes the administration and general management of the organization, the Chief Executive Officer and Chief Reliability Officer, Board of Trustees fees and expenses, communications, external affairs and government relations, office rent, and support of the activities of the NERC Member Representatives Committee and the Regional Entity Management Group.

Legal and Regulatory provides legal support to the organization, including to management, and the Reliability Standards, Compliance Analysis and Certification and Registration, Reliability Risk Management, and RASA Programs, as well as general corporate legal support in areas including antitrust, corporate, commercial, insurance, contracts, employment, real estate, copyright, tax, and other areas.

IT supports NERC's computing, Internet, database and electronic data storage and maintenance, and telecommunications needs, programs, applications and infrastructure, including management of the development and implementation of new software applications and infrastructure. The capital expenditure projects managed by IT represent capital expenditures in hardware, software and associated tools to securely gather, store, analyze and maintain data across the ERO Enterprise to support the ERO's operations, as well as necessary acquisition and replacement of computers, servers and related devices. IT's 2017 activities are focused on NERC infrastructure and support; improving, enhancing, or replacing existing functionalities; ERO Enterprise infrastructure and support; and ERO Enterprise new functionalities.

Human Resources manages all of NERC's human resources functions, including staffing, benefits administration, employee relations, performance and compensation management, succession planning, and training and development. Human Resources also obtains compensation studies, effectiveness studies, and other compensation consulting services when needed.

Finance and Accounting manages all finance and accounting functions of NERC, including employee payroll, 401(k), 457(b) and 457(f) plans, travel and expense reporting, monthly financial reporting, sales and use tax, meetings and events planning and services, insurance, internal audit, facilities management, development of the annual business plan and budget, and the ERO risk management framework.

The major activities of NERC's Administrative Services Departments satisfy the following criteria:

I.A: Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure (ROP)?

II.A: Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

II.D: Is the activity necessary or appropriate for conducting, participating in or overseeing compliance monitoring and enforcement activities pursuant to the NERC ROP and (through the Regional Entities) the Commission-approved delegation agreements?

III.C: Is the activity necessary or appropriate for investigating, analyzing, evaluating, and disseminating information concerning, the causes of major events and off-normal occurrences, and/or providing coordination assistance, technical expertise and other assistance to users, owners, and operators of the Bulk Power System in connection with Bulk Power System major events and off-normal occurrences, but not real-time operational control of the Bulk Power System?

V: Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)? (The applicable Rules of Procedure provision for the major activities of Finance and Accounting is §1100.)

VI: Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and the applicable provisions of Commission orders.

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

XI: Is the activity a governance or administrative/overhead function, activity or service necessary or appropriate for the activities encompassed by the other criteria and, in general, necessary and appropriate to operate a functioning organization?

NERC WRITTEN CRITERIA FOR DETERMINING WHETHER AN ACTIVITY IS ELIGIBLE TO BE FUNDED UNDER SECTION 215 OF THE FEDERAL POWER ACT

For purposes of internal management approval of a proposed new activity or group of related activities ("major activity"), the proposed activity or major activity must be shown to fall within at least one of the criteria listed below. When sub-criteria are listed below a roman numeral numbered major criterion, the proposed activity should be a positive answer to at least one of the sub-criteria. Conversely, an activity that falls under a sub-criterion should pertain to the subject matter of the major criterion.

NERC's annual business plan and budget will describe how each major activity falls within one or more of the criteria listed below. If the major activity is substantially the same as a major activity that was shown to fall within the criteria in a previous year's business plan and budget, the current year's business plan and budget can refer to the prior year business plan and budget.

A determination that an activity falls within FPA §215 does not necessarily mean that NERC will propose or undertake such activity. The determination of whether an activity falling under FPA §215 should or will be undertaken in a given budget year will be addressed in the context of the applicable business plan and budget and will include opportunities for stakeholder input.

The criteria listed below are not necessarily each distinct from the others. An activity or major activity may fall within more than one of the criteria listed below.

I. Is the activity necessary or appropriate for the development of Reliability Standards?

   A. Is the activity necessary or appropriate for Reliability Standards development projects pursuant to the NERC Rules of Procedure (ROP)?

   B. Is the activity necessary or appropriate for providing guidance and assistance to Regional Entities in carrying out Regional Reliability Standards development activities?

   C. Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information for Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed, existing Reliability Standards could be revised, or existing Reliability Standards could be eliminated, such as:

      1. Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System[46] based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

      2. Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences and near miss events?

   D. Is the activity necessary or appropriate for the provision of training and education concerning Reliability Standards development processes, procedures and topics for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel?

II. Is the activity necessary or appropriate for the monitoring and enforcement of compliance with Reliability Standards?

   A. Is the activity necessary or appropriate for the identification and registration of users, owners, and operators of the Bulk Power System that are required to comply with

[46] This document uses the term "Bulk Power System" because that is the term defined and used in FPA §215. NERC recognizes that a different term, "Bulk Electric System," is used to define the current reach of reliability standards. Reliability Standards.

Requirements of Reliability Standards applicable to the reliability functions for which they are registered?

B. Is the activity necessary or appropriate for the Certification of Reliability Coordinators, Transmission Operators and Balancing Authorities as having the requisite personnel, qualifications and facilities and equipment needed to perform these reliability functions in accordance with the applicable Requirements of Reliability Standards?

C. Is the activity necessary or appropriate for the Certification of system operating personnel as qualified to carry out the duties and responsibilities of their positions in accordance with the Requirements of applicable Reliability Standards?[47]

D. Is the activity necessary or appropriate for conducting, participating in or overseeing compliance monitoring and enforcement activities pursuant to the NERC ROP and (through the Regional Entities) the Commission-approved delegation agreements?

E. Is the activity necessary or appropriate for information gathering, collection and analysis activities to obtain information to monitor and enforce compliance with Reliability Standards, including evaluating the effectiveness of current compliance monitoring and enforcement processes, the need for new or revised compliance monitoring and enforcement processes, and the need for new or different means of training and education on compliance with Reliability Standards, such as:

1. Measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

2. Monitoring, event analysis and investigation of Bulk Power System major events, off-normal occurrences, and near miss events?

F. Is the activity necessary or appropriate for the provision of training, education and dissemination of information for/to (i) NERC personnel, (ii) Regional Entity personnel, and (iii) industry personnel with respect to compliance monitoring and enforcement topics and topics concerning reliability risks identified through compliance monitoring and enforcement activities, such as:

1. Requirements of Reliability Standards, including how to comply and how to demonstrate compliance? This includes development of guidance and interpretation documents.

2. Compliance monitoring and enforcement processes, including how to conduct them, how to participate in them, and the expectations for the processes? This includes development of guidance documents.

3. Disseminating, through workshops, webinars, Advisories, Recommendations, Essential Actions, and other publications; "lessons learned" information on compliance concerns and reliability risks obtained through compliance monitoring and enforcement activities; monitoring and investigation of Bulk Power System major events, off-normal occurrences and near miss events, and other Bulk Power System monitoring activities?

[47] Although certification of system operating personnel is an activity falling within the scope of, and eligible to be funded pursuant to, FPA §215, NERC strives to fully fund the costs of this activity through fees charged to participants.

4. Registered Entity internal processes for compliance with Reliability Standards, such as development, implementation and maintenance of internal reliability compliance programs?

G. Is the activity necessary or appropriate for the development and provision of tools and services that are useful for the provision of adequate reliability, because they relate specifically to compliance with existing Reliability Standards and they proactively help avert Reliability Standard violations and Bulk Power System disturbances?

III. Is the activity necessary or appropriate for conducting and disseminating periodic assessments of the reliability of the Bulk Power System or monitoring the reliability of the Bulk Power System?

A. Is the activity necessary or appropriate for the preparation or dissemination of long-term, seasonal, and special assessments of the reliability and adequacy of the Bulk Power System?

B. Is the activity necessary or appropriate for measuring reliability performance – past, present and future; publishing or disseminating the results of such measurements; analyzing the results of such measurements; identifying and analyzing risks to reliability of the Bulk Power System based on such measurements; and/or identifying approaches to mitigating or eliminating such risks?

C. Is the activity necessary or appropriate for investigating, analyzing, evaluating, and disseminating information concerning, the causes of major events and off-normal occurrences, and/or providing coordination assistance, technical expertise and other assistance to users, owners, and operators of the Bulk Power System in connection with Bulk Power System major events and off-normal occurrences, but not real-time operational control of the Bulk Power System?

D. Is the activity necessary or appropriate for awareness of circumstances on the Bulk Power System and to contribute to understanding risks to reliability?

E. Is the activity necessary or appropriate for gathering, analyzing and sharing with and among industry and government participants, information regarding the physical or cyber security of the Bulk Power System?

F. Is the activity necessary or appropriate for the development and dissemination of Advisories/Recommendations/Essential Actions regarding lessons learned and potential reliability risks to users, owners, and operators of the Bulk Power System?

G. Is the activity necessary or appropriate for data collection and analysis of information regarding Bulk Power System reliability matters mandated by the Commission?

IV. Is the activity one that was required or directed by a Commission order issued pursuant to FPA §215? Justification of an activity as a FPA §215 activity based on this category must reference the particular Commission order and directive.

V. Is the activity one that is required or specified by, or carries out, the provisions of NERC's Rules of Procedure that have been approved by the Commission as "Electric Reliability Organization Rules" (defined in 18 C.F.R. §39.1) pursuant to FPA §215(f)?

VI. Is the activity necessary or appropriate for the supervision and oversight of Regional Entities in the performance of their delegated responsibilities in accordance with FPA §215, 18 C.F.R. Part 39, the Commission-approved delegation agreement between NERC and the Regional Entity, the NERC ROP, and applicable provisions of Commission orders?

VII. Is the activity necessary or appropriate to maintain NERC's certification as the Electric Reliability Organization? This Criterion includes conducting periodic assessments of NERC's and the Regional Entities' performance as the Electric Reliability Organization as required by 18 C.F.R. §39.3(c).

VIII. Does the activity respond to or is it necessary or appropriate for audits of NERC and the Regional Entities conducted by the Commission?

IX. Is the activity necessary or appropriate for NERC and Regional Entity committees, subcommittees and working groups engaged in activities encompassed by one or more of the other criteria?

X. Is the activity necessary or appropriate for the analysis and evaluation of activities encompassed by one or more of the other criteria for the purpose of identifying means of performing the activities more effectively and efficiently?

XI. Is the activity a governance or administrative/overhead function, activity or service necessary or appropriate for the activities encompassed by the other criteria and, in general, necessary and appropriate to operate a functioning organization? (Should NERC perform any non-FPA §215 activities, the costs of governance and administrative/overhead functions must be appropriately allocated.)
NERC's current governance and administrative/overhead functions are carried out in the following program areas:

A. Technical Committees and Members' Forum Programs

B. General and administrative (includes, but is not limited to, executive, board of trustees, communications, government affairs, and facilities and related services).

C. Legal and Regulatory.

D. Information Technology

E. Human Resources

F. Accounting and Finance.

The following matters are excluded from the scope of FPA §215 activities. While a list of non-FPA §215 activities would be infinite, the following excluded matters are listed here because they are expressly referred to in FPA §215, the Commission's ERO regulations and/or a Commission order issued pursuant to FPA §215:

A. Developing or enforcing requirements to enlarge Bulk Power System facilities, or to construct new transmission capacity or generation capacity, or requirements for adequacy or safety of electric facilities or services.

B. Activities entailing Real-time operational control of the Bulk Power System.

C. Activities pertaining to facilities used in the local distribution of electricity.

Exhibit C – Contractor and Consulting Costs

Program	Consultants & Contracts	2016 BUDGET	2017 BUDGET	2017 vs 2016 Budget
Compliance Assurance	Reliability Assurance Initiative	200,000	50,000	(150,000)
	Compliance Assurance	**200,000**	**50,000**	**(150,000)**
Event Analysis	Reliability Assurance Project Support	56,000	-	(56,000)
	Event Analysis	**56,000**	**-**	**(56,000)**
Compliance Investigation, Registration and Certification	Risk-based Registration Phase 2 - Consulting Support	50,000	-	(50,000)
	Compliance Investigation, Registration and Certification	**50,000**	**-**	**(50,000)**
Reliability Assessments and System Analysis	Reliability affects of GMD	100,000	100,000	-
	Reliability consulting support	475,000	425,000	(50,000)
	Reliability Assessments and System Analysis	**575,000**	**525,000**	**(50,000)**
Performance Analysis	GADS/TADS/DADS/SED	509,039	528,082	19,044
	Performance Analysis	**509,039**	**528,082**	**19,044**
Situation Awareness	Reliability Tools	576,300	619,150	42,850
	Secure Alerting System	141,000	96,000	(45,000)
	SAFNR - Phase II	438,200	505,700	67,500
	Communication network (NERCnet replacement)	55,975	75,000	19,025
	Situation Awareness	**1,211,475**	**1,295,850**	**84,375**
E-ISAC	**GridEx Support**	-	250,000	250,000
	Program-Level Capabilities	366,500	353,000	(13,500)
	Software & Services	113,285	113,285	-
	Events & Outreach	50,550	50,550	-
	CRISP	5,888,594	5,888,594	-
	E-ISAC and CRISP	**6,636,929**	**6,788,429**	**151,500**
System Operator Certification	System Operator Testing Expenses	59,400	62,000	2,600
	System Operator Examination Development	69,000	70,000	1,000
	Database Development	24,000	-	(24,000)
	Database Maintenance	25,200	37,800	12,600
	SOCCED Database Improvement Project (funded from Working Capital generated from fees in excess of expenses)	150,000	50,000	(100,000)
	System Operator Certification	**327,600**	**219,800**	**(107,800)**
Training and Education	Continuing Education Program	133,200	145,800	12,600
	Web-based course hosting (Learning Management System)	55,000	55,000	-
	Enhanced Platform	-	-	-
	Course development and Support - External Training	125,000	125,000	-
	NERC Staff Technical Training	35,000	35,000	-
	Continuing Education, Training & Education	**348,200**	**360,800**	**12,600**
General & Administrative	Communications support	15,000	15,000	-
	0	-	-	-
	ERO Effectiveness Survey	80,000	-	(80,000)
	General & Administrative	**95,000**	**15,000**	**(80,000)**
IT	ERO Development & Support	988,671	1,161,787	173,116
	ERO Data Analysis	100,000	200,000	100,000
	Applications Enhancements, Consulting and Help Desk Support	1,006,000	851,000	(155,000)
	Information Technology	**2,094,671**	**2,312,787**	**218,116**
HR	Training and Development	325,000	350,000	25,000
	Compensation Consulting	100,000	100,000	-
	Employee, industry and Board Surveys	50,000	50,000	-
	HR Consulting Services	75,000	75,000	-
	Human Resources	**550,000**	**575,000**	**25,000**
Finance	Internal Controls and Outside Auditor Consulting Support	200,000	300,000	100,000
	Finance and Accounting Support	97,000	97,000	-
	Finance and Accounting	**297,000**	**457,000**	**160,000**
	TOTAL CONSULTANTS AND CONTRACTS	**12,950,914**	**13,127,749**	**176,835**

Exhibit D – Capital Financing

The company successfully closed on its capital financing program on January 10, 2014. The interest rate is floating and equal to LIBOR plus 275 basis points, which yielded a rate of 2.91% at closing.[48] The total size of the non-revolving credit facility is $7.5M, with the total authorized borrowings each year limited to the amount approved by the Board of Trustees and FERC in that year's business plan and budget for IT hardware and the costs of developing software applications. Consistent with the terms of the loan documentation and its Board and FERC-approved 2014 budget, the company made an initial draw of $1.265M at the end of January 2014 related to 2013 expenditures. The company recorded new capital investments of approximately $1.65M in 2013 related to the development of software applications and IT hardware,[49] a portion of which was financed with the proceeds from this initial draw. This borrowing is amortized over three years, commencing January 31, 2014, and can be prepaid without penalty. A balance of $1.416M was available for draw during 2014, which was also consistent with NERC's 2014 approved budget. However, the company had sufficient funds available to pay for budgeted capital improvements without having to draw on this credit facility. A balance of $1.9M was available for draw during 2015, consistent with NERC's 2015 approved budget. New capital investments of $1.85 were financed with draws late in 2015 and early 2016. These new borrowings are also being amortized over three years, beginning January, 2016 and April, 2016. The company is in discussions with the lender about renewing this facility going into 2017, with terms and conditions of the renewed facility similar to those in the current agreement.

As further discussed in the Introduction and Executive Summary and in Section A, General and Administrative and set forth in the table below, NERC has a 2017 proposed capital budget of approximately $4.4M, $1.45M of which it is proposing to finance.

NERC CAPITAL BUDGET	2016	2017
ERO Application Development	$ 1,500,000	$ 700,000
E-ISAC Portal Development		1,000,000
Document Management	465,000	335,000
Hardware (Storage, servers, laptops)	955,000	991,000
Other Equipment	535,000	885,000
Disaster Recovery	200,000	150,000
NERC Software licenses	256,000	311,000
Total Capital Budget	**$ 3,911,000**	**$ 4,372,000**

The table below sets forth the projected principal and interest repayment schedule for the amounts financed to date and the additional planned $1.45M in capital financing. This projection assumes an average interest rate of 3.5% over the term of the financing, which is consistent with the 2014 budget. Management is recommending that 3.5% continue to be used given the potential for interest rate increases during 2016. The actual interest rate and interest rate expense will be reflected in the quarterly budget to actual variance reports the company posts on its website, reviews in open session with the NERC Finance and Audit Committee, and files with FERC. Any variations in interest expense will be captured and reported as a contribution to operating reserves, the expenditures of which are subject to the terms of the company's Working Capital and Operating Reserve Policy.

[48] The interest rate at closing was lower than projected for purposes of the 2014 budget. As detailed in the company's approved *2014 Business Plan and Budget*, any difference between actual and budgeted interest expense for draws under the credit facility becomes an addition to the company's Unforeseen Contingency Operating Reserve balance.

[49] This capital investment amount is exclusive of approximately $640k in expenses which were incurred in 2013 in the development of the Events Information Data System application and expensed rather than capitalized, as further discussed in the company's Q1 2014 budget variance report presented to the NERC Finance and Audit Committee.

	YEAR-END OUTSTANDING DEBT BALANCE					
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
2013 Expenditure / Closed 2014	$ 878,472	$ 456,806	$ 35,139	$ -	$ -	
2015 Budgeted	-	-	1,234,547	617,274	-	
2016 Budgeted	-	-	1,500,000	666,667	333,333	
2017 Projected	-	-	-	1,450,000	966,667	483,333
2018 Projected	-	-	-	-	1,800,000	1,200,000
Total Outstanding Balance	$ 878,472	$ 456,806	$2,769,686	$2,733,940	$3,100,000	$1,683,333

	ANNUAL PAYMENTS FOR DEBT SERVICE					
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
2013 Expenditure / Closed 2014	$ 386,528	$ 421,667	$ 421,667	$ 35,139	$ -	
2015 Budgeted	-	-	617,274	617,274	617,274	
2016 Budgeted	-	-	-	333,333	333,333	333,333
2017 Projected	-	-	-	-	483,333	483,333
2018 Projected	-	-	-	-	-	600,000
Interest Expense	29,367	24,826	56,529	56,725	61,170	72,203
Total Principal and Interest Costs	$ 415,895	$ 446,493	$1,095,469	$1,042,471	$1,495,110	$1,488,869

Exhibit E – Working Capital and Operating Reserve Amounts

In February 2015, the NERC Board approved an amendment to the Company's Working Capital and Operating Reserve Policy. A number of changes were made to the policy, including:

- Clarifying the definition of working capital to represent funding needed for cash flow purposes due to the timing of the receipt of funds and the payment of expenses.
- Creating four separate categories of operating reserves:
    1. A new subcategory of reserves entitled **Future Obligation Reserve** for funds that are being held to satisfy obligations that will be settled in a future year. Examples include leases, certain contracts, and credit agreements. These reserves were previously within the definition of working capital and are more accurately classified as a form of operating reserve.
    2. Continuation of a separate category of reserves for the Operator Certification Program called the **Operator Certification Reserve**.
    3. Elimination of the Known and Unforeseen Contingency categories of operating reserves and creating a single category of contingency reserves called the **Operating Contingency Reserve**.
    4. Creation of a separate category of reserves for CRISP called the **CRISP Reserve**.

Working Capital

Based on its 2016 cash flow projection and taking into account the historic manner in which NERC's assessments have been billed and paid, NERC does not anticipate needing access to working capital in 2017 to meet monthly cash flow needs. While individual reserve categories are increasing and decreasing based on operating needs and uses, the budget in total does not reflect additional net funding for reserves. In the unlikely event NERC experiences a temporary cash flow shortage, it has the ability to either request authorization from the Finance and Audit Committee and Board of Trustees to temporarily access operating contingency reserve funds, or draw on its $4M line of credit, as long as NERC is in compliance with the covenants under its bank credit agreement.

Operating Reserves

Total operating reserves are projected to be $5.5M among all four categories. The Future Obligation Reserve is budgeted to be $2.6M and is primarily funds held to offset future liabilities under lease agreements for the Atlanta and Washington, DC, offices. System Operator Certification Reserves are budgeted at $714k and the Operating Contingency Reserve is budgeted for $2.2M. The CRISP Reserve (budgeted at $500k) is held pursuant to the terms of the Master Services Agreement between NERC and participating utilities, which calls for a separate third-party funded reserve established to fund certain contingencies in connection with CRISP.

In addition to the foregoing reserves, the amended policy also provides for the creation of an **Assessment Stabilization Reserve.** The goal of the Assessment Stabilization Reserve is to mitigate assessment volatility and have changes in annual assessments track, within a reasonable band, changes in the company's total annual budget, with the total budget reflecting prudent fiscal discipline and good stewardship of resources. Assessment stabilization funds will be used when available to help stabilize assessments and mitigate year-to-year swings in assessments. Those swings primarily result from the application of penalty funds, but could also result from other factors like surplus funds available from a prior period, the need to replenish the Operating Contingency Reserve, or significant but relatively short-term operating or capital spending needs. Pending NERC Board approval of the release of restricted penalties into this reserve, the balance on January 1, 2017 will be $2.7M and has, to date, been funded entirely by penalties. NERC is proposing to use $1.1M of the balance to offset 2017 U.S. assessments. An additional penalty is expected in May 2017 for $500,000. This penalty results from a settlement reached through WECC related to the September 2011 blackout.

E-ISAC
ELECTRICITY INFORMATION SHARING AND ANALYSIS CENTER

Exhibit F - From Portal to Platform

A Capabilities Case for Improving Information Sharing in the Electricity Sector

RESILIENCY | RELIABILITY | SECURITY






Why Information Sharing Matters

- Cyber and physical threats do not come from machines
  - They originate in the minds of human adversaries
  - Cyberspace is just a tool for the adversary
  - So are explosives, weapons, truck bombs, bolt cutters and social engineering
- Threat actors typically don't work alone
  - Strategic "existential" threats (the ones we should worry about) are typified by large, well connected organizations
  - These groups routinely share, collaborate, and analyze situations freely, using every tool available including the Internet and technology
- Our challenge is to be better at sharing, collaborating, and analyzing than our adversaries
  - We need better tools than those they have

Membership Involvement

- ESCC Strategic Review (July 2015) called for continued improvement to the portal
  - Recommended the use of STIX/TAXII standards
  - Recommended the exploration of ways to automate information sharing and analysis
- Updated portal launched in September 2015
- GridEx III Simulation Deck portal used in November 2015 offered several new ideas about grid security visualization
- MEC's OTT working group developed a comprehensive list of portal improvement recommendations

Portal to Platform Timeline

- 2016:
  - Fix existing portal bugs and issues identified by the E-ISAC and members
  - Build incremental improvements to meet short-term recommendations
  - Conduct scoping/discovery effort for transition to platform
  - Validate requirements with membership
  - Launch new “look and feel” for existing portal
- 2017:
  - Install new hardware
  - Launch new platform
  - Build incremental improvements to meet long-term requirements
  - Ongoing membership feedback

Expected Benefits

- Dramatic improvement to information sharing
  - Human to human via text, discussion, document, photo, etc. sharing
  - Machine to machine via built in STIX/TAXII compatibility
- Rapid response to emerging critical situations
  - Situational awareness of physical and cyber events
  - Coordination within and external to the Electricity Sector
- Extendable as new technologies emerge
  - Easy integration with mobile technologies
  - Designed to be modular and adaptable to future capability requirements
- Increased trust in the E-ISAC
  - Will result in increased sharing and collaboration

Portal vs Platform

- Existing portal characteristics
  - Designed for a specific audience with a specific purpose
  - Static content with infrequent changes
  - No user control over look/feel of layout
  - Not designed for high levels of interaction
  - Limited search capability
- Proposed platform characteristics
  - Designed for a wide audience with different needs
  - Highly customizable by users
  - Extendable to accommodate new technologies
  - Visual and graphical orientation (vs text-based)
  - Robust search, filtering, and native language queries of datasets
  - Server-side computation and analytics

Project Management

- Total proposed 2017 budget of $1 million
- Two parallel projects
  - Near-term quick fixes and user interface improvements
  - Long-term movement to a platform with significant changes
- Project implementation managed by NERC CTO and the ERO IT PMO
- Disciplined approach used to successfully manage and implement other recent IT projects
- Ongoing MEC engagement
- Scope will be managed within approved budget

MEC Feedback

- MEC briefed at June 15, 2016 face-to-face meeting
- Bill Spence (Chairman, President and CEO, PPL Corporation, Inc. and Chair, E-ISAC Member Executive Committee) briefed EEI's Executive Committee on June 14, 2016 and provided positive feedback
- The MEC provided NERC with written comments in support of the proposed funding on or before June 30, 2016.